BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
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PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2008-0273
	)	
Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs.	)	
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TAWHIRI POWER LLC'S
OPENING BRIEF;

EXHIBITS "A" THROUGH "F";

AND

CERTIFICATE OF SERVICE

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TAWHIRI POWER LLC'S
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TO THE HONORABLE PUBLIC UTILITIES COMMISSION OF THE STATE OF HAWAII:

Pursuant to the Hawaii Public Utilities Commission's (the "Commission") Order Granting The County Of Hawaii's Motion For Approval To Amend its Status As An Intervenor To A Participant, Filed On April 8, 2009; Granting The City And County Of Honolulu's Motion For Approval To Amend its Status As An Intervenor To A Participant, Filed On April 8, 2009; Amending Hawaii Holdings, LLC, Doing Business As First Wind And Sempra Generation's Status As Intervenors To Participants; And Amending The Schedule In This Proceedings, filed herein on April 27, 2009, as amended by the Commission's letter dated May 21, 2009 (collectively "Procedural Order II"), TAWHIRI POWER LLC ("TPL") hereby submits to the Commission its Opening Brief. TPL's two (2) Consultants and Expert Witnesses, Dr. Mohamed El-Gasseir and Mr. Harrison Clark, have provided invaluable assistance in preparing this Opening Brief, as well as the other pleadings and documents submitted on behalf of TPL herein. The Curricula Vitae of Dr. El-Gasseir and Mr. Clark were provided to the Commission on April 8, 2009, and a courtesy copy of the same is attached hereto as Exhibit "A" and made a part hereof.

I. INTRODUCTION:

This Opening Brief addresses the FiT Program design principles that TPL views will result in a cost-effective and sustainable movement towards extensive renewable energy penetration of the electric power supply. It also discusses existing and proposed actions from other sources which, if implemented, will produce the opposite effect: ill-conceived, unsustainable and henceforth short-lived FiT programs. Before doing so, TPL directs the Commission's attention to two major misunderstandings which continue to confuse and side-track the FiT discussions since its inception, namely:

- Persistent association of system frequency deviations with wind generation; and
- Frequent suggestions to eliminate the Public Utilities Regulatory Policy Act (PURPA) in order to substantially increase the acceptance of renewable energy generation into the utility's grid.

TPL is concerned the above misconceptions and assertions may have already created a bias which if left unchecked, would lead to an ill-designed FiT Program haphazardly implemented in conjunction with other mechanisms for accelerating renewable energy development. Therefore, TPL will begin this Opening Brief by setting the record straight regarding these two misconceptions before addressing the FiT design principles.

A. Associating Wind with Poor Utility System Performance Is Baseless, Reckless, Misleading and Could Lead to Very Costly Resource Planning Decisions

On numerous occasions throughout these proceedings, HELCO/HECO representatives have made allegations associating their system frequency control problems with the operation of TPL's Pakini Nui wind farm on the Big Island.[1] The primary piece of information, or rather misinformation, that has been repeatedly used on those occasions is a graph showing simultaneously the chronologic profiles of Pakini Nui output energy and HELCO's system frequency.[2] This method of imparting association without presenting any evidence of a cause and effect relationship and by neglecting to mention there is at least

[1] See e.g., HECO's Response to PUC-IR-6 filed herein on March 18, 2009.
[2] See footnote 1, infra.

the possibility of other explanatory factors has found its way formally into the FiT Docket record as part of a Power Point presentation prepared by General Electric (GE).[3]

It may be argued whether the impact of wind generation on system operation is a proper subject for discussion in a proceeding dedicated to formulating FiT Programs. However, repeated dissemination of misinformation such as the aforesaid graph could divert the planning and implementation of renewable energy growth away from identifying and implementing least-cost renewable energy investment strategies for Hawaii. Resource quality and availability considerations, relatively small footprint requirements and economy of scale advantages, make medium to large wind generation projects essential for the formulation of economically balanced renewable energy portfolios for the Hawaiian Islands, including the FiT Program. For this reason, TPL respectfully submits the following comments:

- TPL is in receipt of a study conducted by General Electric and another conducted by Electric Power Systems that have been referenced by HELCO in the FiT process.[4] Others were referenced in FiT filings but are not available to the Intervenors.[5] The two studies that are available to TPL do not support the claims HELCO expressed concerning frequency variations.[6]

- TPL has conducted its own investigations to establish with certainty that the vast majority of the cited frequency deviations in the HELCO system, including the most onerous ones, are not related to contemporaneous operation of TPL's wind farm at Pakini Nui, and that any effects traceable to Pakini Nui are spurious at best.[7] The same cannot be said for older wind farms that rely on turbines pre-disposed to inherently follow wind variations more closely or have less sophisticated controls. Nonetheless, future wind farms will use technology similar to the one in place at TPL's wind plant and thus will be relatively innocuous.

- Small wind plants intended for limited markets created by FiT programs in the Islands could add to problematic frequency issues. However, the multiplicity and locational diversity of such installations will allow variations in the timing, magnitudes, and direction of wind speed

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[3] GE Global Research and University of Hawaii – Hawaii Natural Energy Institute, *Summary Report On Stakeholder Workshop*, November 2007.
[4] See Section H of this Opening Brief and Exhibit "F" attached hereto.
[5] See The HECO Companies' Submission Of Supplemental Information filed herein on May 8, 2009.
[6] See generally Exhibit "F".
[7] Documentation to support this statement is not provided herein because the same involves a matter presently in dispute between HELCO and TPL, and the subject of "Privileged and Confidential Communication Subject To Rule 408, HRE and FRE". See also, Tr. Vol. III, at 241, ln. 7-12.

changes to greatly reduce such impacts on the grid. (E.g., When power is rising at some plants it will be falling at others with the net effect being considerably less.)

- The aforementioned chart that appeared in the GE report and used in HECO/HELCO slide presentations on the alleged ill effects of wind resulted from a series of events on the second day of operation of the TPL wind farm. Several wind turbines entered a power down process as the result of protection issues. Those issues were quickly rectified and have not occurred since.

- Other charts that have been presented to characterize the impact of large wind farms on Island frequency, and used again in the GE report, have in fact reflected times when HELCO's spinning reserve was below normal or exhausted, or the AGC system was off-line or improperly tuned.[8]

- In one example, an arbitrary simulation shows an apparent deleterious impact of increasing the size of a wind farm. That case does not reflect the reality of adding wind plants, large or small, to an island system because it neglects the diversity among wind plant sites mentioned previously.

- Much of the lingering mythology concerning the alleged adverse impacts of wind turbines on small utility system frequency is rooted in experiences dating back to the 1980s when induction machines were primarily being utilized. Today's wind turbine technology is vastly more advanced such at some wind farms are employed to provide ancillary services. See Exhibit B attached hereto and made a part hereof which documents the case of a Danish offshore facility (Horns Rev) that is being used to provide such services.

- The turbine technology that TPL relies on at Pakini Nui is the same as the one used at the Horns Rev wind farm.[9]

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[8] See footnote 1, <u>infra</u>.

[9] J. Charles Smith, <u>et al.</u>, *A Mighty Wind*, IEEE Power & Energy Society, March/April 2009, at 49-51. In Denmark, the Horns Rev Offshore Wind Farm utilizes its frequency controls during off-peak hours "to provide a spinning reserve that can be used in case of underfrequency." <u>Id</u>. at 51. A copy of this article is attached hereto as Exhibit "B" and the referenced quote may be found at page 15.

- Frequency variations on the HELCO system are not only caused by wind farms. Some of the largest frequency excursions result from trips of HELCO's own generators, and HELCO's operating practices of providing spinning reserve and curtailing wind farms.

- Any legitimate curtailment of energy deliveries from Pakini Nui should only occur during: (i) system emergency conditions not caused by the TPL facility, or (ii) minimum load periods due to a lack of dispatch flexibility within HELCO's fossil-fueled system.

B. Statements Dismissing the Public Utilities Public Policies Act Are Misguided and Harbor Underlying Irrational Rejection of the Concept of Avoided Utility Costs

Since its enactment in 1978, this landmark federal legislation has initiated and continued to sustain the movement toward renewable energy resources. It goes without saying that PURPA energy policy making facilitated and encouraged states like Hawaii is seriously consider implementation of Feed-in Tariff programs. PURPA also devised and instituted the concept of avoided utility costs as a metric for compensation. The application of this yardstick for determining and benchmarking compensation for non-utility generation led to the development of the least-cost planning methodology, which in turn transitioned utilities into the integrated resource planning approach. PURPA's influence is evident throughout these proceedings. During the Panel hearing, the Moderator proposed revisiting the definition of avoided utility costs to benchmark and assessing the reasonableness of future FiT rates (prices) for renewable energy purchases.[10] This subject will be addressed in detail in the following sections of this Opening Brief.

Critics of PURPA fall into two groups: (1) developers who view avoided-cost based compensation as being too low to encourage rapid deployment of certain renewable energy technologies; and (2) utilities and their allies who view paying independent power generators at prices based on avoided utility costs as being excessive and a "relic of the past". Although their motivations differ, the net result is a unified rejection of PURPA. With respect to the first group, there will be FiT programs designed to pay small generating units at prices exceeding utility avoided costs. Diseconomy of scale effects, and the fact that the current methodology for determining avoided costs tends to significantly underestimate them, are very likely to project overly priced FiT programs.[11] As a result, the intended pace of renewable energy development at the distribution level will be modest at best. For the second group, a competitive

[10] Tr. Vol. V, at 37, ln. 11-19 and 40, ln. 8-16.

[11] This issue is dealt with in a subsequent section of this Opening Brief.

bidding process will yield several rounds of requests for proposals (RFPs) with the contracts arising from them most likely being awarded to the largest renewable project developers capable of undertaking the biggest projects. The unacceptable consequence of this approach will lead to limited competition and projects being too large and geographically too concentrated for Hawaii's relatively small utility systems, especially on the Big Island and Maui.

Another objectionable consequence of the current crusade against PURPA and the avoided cost methodology is the failure to capture the mid-size generation investment opportunities; somewhere within the range of approximately 0.5 MWs and 25 MWs. This investment band would offer reasonable economy of scale cost advantages without loss of the resource diversity and reliability advantages that are associated with multiple sites, operators and size limitations in relation to system loads. It is simply not in the interest of the ratepayers or Hawaii's economy to erect any barriers to the continued development of mid-size projects by siphoning off an already limited market to cater to the interests of large investors. Instead, PURPA offers a mid-course recruitment mechanism for medium-sized projects which are well-suited for small systems, especially the HELCO and MECO utilities and to some extent the Oahu grid as well. This is already evident by reason of the high renewable energy penetration on the Big Island despite HECO's procedures for determining avoided utility costs have been neither transparent nor adequately vetted.

II. ARGUMENTS:

A. THE "DO NO HARM" CONCEPT SHOULD BE THE OVERRIDING PRINCIPLE AND CONSIDERATION IN THE FORMULATION AND IMPLEMENTATION OF A FiT PROGRAM

As stated by the HECO Companies in its responses to the Information Requests, they "already curtail generation, including renewable energy generation, in order to maintain system reliability, such as during times of high wind generation at minimum system load periods. **Adding additional variable generation via the FIT that is not controllable may increase the amount and frequency of existing renewable generation that is curtailed.**" DBEDT-IR-2 (HECO) filed herein on February 11, 2009, at page 2 of 3 [emphasis added]. Consequently, the HECO Companies are proposing "annual FIT quantity targets and requirements for curtailment of certain types of FIT resources". Id.

Experiencing first-hand the adverse consequences of energy deliveries' curtailment,[12] TPL proposed from its very first pleading filed herein on December 31, 2008 the concept of "**do no harm**" as the guiding principle for the Commission to consider in developing and implementing a feed-in-tariff program ("DNH Policy"). See Exhibit "C" attached hereto for the Response to NPRI Paper on Feed-In Tariffs in Docket No. 2008-0273 By Mohamed M. El-Gasseir, Ph.D. on behalf of Tawhiri Power LLC, a copy of which was attached to TPL's Comments To Scoping Paper filed herein on December 31, 2008 as Exhibit "A". As cautioned by TPL:

> it is imperative the Project-Based Feed-In Tariff mechanism [to] be considered for adoption by the Commission "**do no harm**" to the economic viability of [its] Pakini Nui [Wind Farm] and other pre-existing renewable generators. In fact, fairness and efficiency require properly designed Feed-In-Tariffs **do no harm** to any prior investment, including projects developed in the future through any renewable energy development program.

Tawhiri Power LLC's Final Statement Of Position Regarding Feed-In Tariff Designs, Policies And Specific Pricing Proposals filed herein on March 30, 2009 ("Final Statement") at 3 [emphasis in original].

It is in conjunction with this DNH Policy which should govern the design and implementation of the FiT Program that TPL agrees with certain aspects of the HECO Companies' Straw Tariff filed herein on December 23, 2008. As will be more fully explained in this Opening Brief, TPL proposes the FiT Program should:

(a) begin with an Initial Phase which should be limited to a period of 1 or 2 years of

[12] See Tr. Vol. III at 218, ln. 22 to 219, ln.10, and TPL's Submissions of Information at 10 filed herein on May 8, 2009.

engaging small-scale generators at the distribution level ("FiT Distributed Generation") to gather valuable information and experience for developing a follow-up phase tasked to fully implement the FiT Program;

(b) establish an annual all-technologies combined cap on the targeted FiT Distributed Generation established at the higher of 3 megawatts, or the average growth of demand over the previous 5 years for the HELCO system, during this Initial Phase[13];

(c) "unbundle" the FiT tariff-based payments into a base price that assumes no prospect for uncompensated curtailment of production, an interconnection adder to fund utility-published location specific interconnection charges, and a monthly adjustment for compensating generators for incurred curtailments, with the base price component being limited to "the cost of generation plus a reasonable profit"[14] to the FiT developer;

(d) develop an accurate and readily verifiable mechanism for determining and regularly updating utility avoided cost and applicable adders to provide a baseline for identifying the renewable generation technologies that could be affordably supported by carefully designed FiT programs;

(e) coordinate closely the FiT Proceedings and a fully transparent and efficient Clean Energy Scenario Planning process ("CESP"); and

(f) conduct independent system planning studies for each HECO Company system in a fully transparent manner to determine the best cost-effective roadmap to achieve maximum transformation to renewable generation grids at the fastest affordable pace possible without degrading service reliability or quality by identifying and utilizing the best mix of development

[13] Since TPL only has experience and concerns with the HELCO system, the details for this proposed Initial Phase only relates to that grid. However, the Commission is invited to apply the applicable aspects of the proposed Initial Phase to the MECO and/or HECO systems as its deems appropriate.
[14] HSEA IR#2 (HECO) filed herein on February 11, 2009, at 1.

strategies and programs, including FiT generators, PURPA-based IPPs, Schedule Qs), etc..

B. A PHASED FiT DEVELOPMENT APPROACH IS ESSENTIAL FOR THE HELCO SYSTEM CONSIDERING THE CURRENT STATE OF ELECTRICITY GENERATION AND DEMAND ON THE BIG ISLAND.

At the Panel II Hearing held on April 13, 2009, HECO repeatedly advised the Commission the system grids of HECO, MECO, and HELCO are markedly different from each other in terms of their ability to accept additional renewable generation. See generally Tr. Vol. V, at 67, ln. 21 to 68, ln. 12. For instance, HELCO confirmed Commissioner Leslie H. Kondo's description of the penetration levels of as-available renewable generation being taken in by its system grid as being "maxed out". Tr. Vol. I, at 209, ln. 20 to 210, ln. 5. In other words, the HELCO system cannot accept additional renewable generation without "mitigat[ing] the impacts of the existing as-available resources[, unless they are small generators who] don't contribute significantly to the existing [interconnection and integration] issues". Id. at 209, ln. 10-14. Therefore, as Dr. El-Gasseir stated a "state-wide cap" for the FiT Program would not make sense. Tr. Vol. V, at 69, ln. 13-20. Instead, the better approach would be "on an interim basis, maybe for one or two years at the most, that the cap will be equal to an average, the average load growth, or five years for each system." Id. at 69, ln. 24 to 70, ln. 1.

The HELCO system is drastically different from the HECO system. The former is presently approaching its limit in accepting additional as-available renewable generation without instituting major and fundamental changes to its operating parameters. The state of electricity demand and supply, and the high penetration of renewables on the Big Island, may be considered the harbinger of future problems the substantially larger grid on Oahu may experience with the implementation of the FiT Program. Therefore, designing the FiT Program carefully and correctly for the Big Island will facilitate its design and implementation for the other islands. Additionally, it must be acknowledged from the outset the FiT Program should be designed differently for each grid. To a certain extent, HECO appears amenable to this approach. See generally Id. at 68, ln. 8-12.

Proceeding with the above understanding and appreciation of the differences between the grids on each island, TPL recommends designing and implementing the FiT Program for the Big Island in two phases; an initial one to be implemented immediately ("Initial Phase"), and the second one operated under a contract for the remaining term of the applicable FiT contract period. The Initial Phase should be limited to one or two years, at the most, to gather the information and gain the experience necessary to design the second phase of the FiT Program ("Second Phase").

C. THE CURTAILMENT RISKS FOR INDEPENDENT POWER PRODUCERS AND REQUIRED SOLUTIONS AND MEASURES.

Dr. El-Gasseir explained in detail the consequences of curtailing renewable energy production in Exhibit "A" attached to TPL's Final Statement Of Position Regarding Feed-In Tariff Designs, Policies and Specific Pricing Proposals filed herein on March 30, 2009 ("TPL's Final Statement"). That Exhibit "A" is also attached hereto as Exhibit "D" for ease of reference. The solution to this "curtailment problem" was also proposed by Dr. El-Gasseir and included in TPL's Final Statement ("DNH Formula"). As more fully explained hereinafter in this Opening Brief, the DNH Formula is designed to be "revenue neutral" and would not be included in the FiT Rate.

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D. THE FiT PROGRAM SHOULD BEGIN WITH THE FIRST PHASE FOR 1 OR 2 YEARS WITH A COMMITMENT TO EXPONENTIALLY EXPAND IT TO FACILITATE ACHIEVEMENT OF THE ENERGY AGREEMENT GOALS.

As set forth in TPL's Final Statement, the "best design" for Project –Based Feed-In Tariffs ("PBFiTs") to ensure its successful implementation should include the following 5-step approach:

i. **Commence PBFiTs implementation as a "pilot program" at the distribution level beginning with market-proven renewable generation technologies.** [This step should be considered the Initial Phase of the twophase FiT Program.]

ii. Require [during the Initial Phase] all curtailed energy deliveries be compensated at rates no less than the host-utility's short-run avoided costs regardless of whether the generator is a PBFiT seller or an IPP.

iii. Prohibit the utilities, and their subsidiaries and affiliates, from competing for any form of on-site (customer-based) generation, distributed generation or PBFiTs investments because of irreconcilable conflicts of interest.[15] Eliminating even the appearance of a conflict of interest during the infancy phase of the PBFiTs is essential to a proper and objective evaluation of the pilot program while assuring a high level of integrity. This restriction will increase the confidence of ratepayers in the PBFiT Program as they prepare to shoulder the burden of furthering Hawaii's clean energy and energy independence goals in the present tumultuous economic environment.

iv. Conduct a thorough and fully transparent evaluation of the potential direct and indirect impacts on ratepayers under this "pilot program". As suggested by many of the Intevenors in this Docket, a 2-year period of review would be adequate to conduct an assessment of the cost of operations of PBFiTs and whether their owners are anticipated to receive reasonable returns on their investments over the anticipated useful life of their projects based upon preliminary revenue and operational results.

v. Direct Hawaii's utilities to prepare short and long-term plans for upgrading their generation, transmission and distribution systems to

[15] Based upon the representations made by the HECO Companies at the Technical Conference and Settlement Discussions Regarding All Parties' Proposals held on March 18-19, 2009 ("Conference"), it appears they are agreeable to this restriction.

> maximize the integration of variable and other forms of renewable generation resources while minimizing the need to curtail them. The costs of these plans would be juxtaposed against the costs of compensating PBFiT and IPP generators for curtailed (undelivered) energy. The results from this analysis and the proposed "pilot program" would enable the Commission to determine the optimal balance between PBFiT growth and utility investments in grid upgrading.

Final Statement, at 9-10 [emphasis added].

As further articulated by Dr. El-Gasseir, this proposed "pilot program"[16] would be based upon, or limited to, the load growth of the different HECO Companies' systems. Tr. Vol. II, at 190, ln. 13-18. Since there was virtually no load growth over the preceding year in any of the islands according to the HECO Companies,[17] Dr. El-Gasseir suggested using the average load growth of each of those systems for the past five (5) years for TPL's First Phase. Tr. Vol. V, at 69, ln. 23 to 70, ln.7. For the MECO system, "that would be somewhere around **3 megawatts**." Id. at 71, ln. 5-9 [emphasis added]. With respect to the HELCO system on the Big Island, "it would be similar to Maui [i.e. MECO], roughly in that range as well, probably equaling in maybe the **3 megawatt level**." Id. at 71, ln. 10-12 [emphasis added].

In summary, TPL proposes the PBFiTs be introduced in the First Phase limiting generation to 3 megawatts for the HELCO and MECO systems. This First Phase would only be "on an interim basis, maybe for one or two years at the most". Id. at 69, ln. 23-24. In other words, as succinctly stated by Commissioner Leslie H. Kondo, it is TPL's "recommendation that the Commission take . . . a **baby step**, in terms of what the FiT cap should be, until [the Commission] get[s] the information that . . . would be important for a real reasonable discussion and then the decision". Id. at 107, ln.17-21 [emphasis added].

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[16] Referred to herein as "Initial Phase".
[17] See generally Tr. Vol. V, at 70, ln. 25 to-71, ln. 12.

E. CURTAILMENT COMPENSATION SHOULD BE "REVENUE NEUTRAL" AND NOT INCLUDED IN THE FiT RATE.

One (1) of the Commission's decisions identified by The National Regulatory Research Institute ("NRRI") for Panel IV was "How should FiT participants be compensated for curtailment?" Exhibit A at 7 attached to the Order Establishing Hearing Procedures filed herein on April 1, 2009 ("Hearing Order"). TPL anticipated this question and answered it squarely with Dr. El-Gasseir's Proposed Solution for the Curtailment Issue attached as Exhibit "A" to its Final Statement ("DNH Formula"), and also attached hereto as Exhibit "D". "The only way to ensuring that the adopted tariff would **do no harm** to any generator – regardless of the type of renewable development program it belongs to [(i.e. PBFiTs, IPPs, Schedule Qs, etc.)] or the vintage of the facility – is to guarantee **revenue neutrality** irrespective of the level of curtailment the generator experiences" via the DNH Formula. See Exhibit "D" attached hereto, at 6. This DNH Formula would be the "best design" for the FiT Program because:

1. It does away with the curtailment problems [as explained in TPL's Final Statement];
2. It reveals system inflexibility costs [and thereby, incentivize the HECO Companies to upgrade their grids to accommodate all renewable energy generation];
3. It meets the fairness criterion [because the FiT generators are paid only for the actual amount they are curtailed, rather than based upon a questionable estimate determined at the time the FiT rate to which they are subject to is adopted by the Commission][18]; and
4. It ends a wrongful policy of penalizing variable (intermittent) resources [because they are not "firm" generators].

[18] Stated another way, Dr. El-Gasseir in his Closing Arguments explained that including compensation for future curtailment in the FiT rate is "actually more inefficient because you end up rewarding those who are not . . . curtailed at all." Tr. Vol. V, at 176, ln. 13-15.

Id. at 8.

As explained by Dr. El-Gasseir in Panel IV, "to make [the FiT Program] successful you have to . . . peel away the curtailment problem, **because nobody can predict that, the curtailment component**." Tr. Vol. III, at 78, ln. 19-22 [emphasis added]. In addition to the "revenue neutral" aspect to the DNH Formula, it would "free the system operator to operate the system as they wish for reliability. That's important for reliability." Tr. Vol. V, at 175, ln.14-16. It is also essential for system safety. "And if you are not comfortable with that concept, . . . why don't you try it for one year . . . in the Big Island [as part of the First Phase of the FiT Program], at least, and see how it works." Id. at 175, ln. 17-20.

Commissioner Kondo posited a question to Dr. El-Gassier with respect to the DNH Formula that if the FiT generator is compensated for the curtailment of its generation, essentially the rate payer is paying twice; once for the curtailed energy and the second time for the energy actually delivered to that rate payer. See Tr. Vol. III, at 219, ln. 20 to 220, ln. 15. Although at first blush this conclusion may seem supportable, Dr. El-Gasseir explained "the problem is the inflexibility of the system. You – you must face the reality that this system, electricity system, has to change very radically. And that's the price of it." Id. at 221, ln.7-9. Therefore, encouraging renewable generation (whether via the FiT Program, other mechanisms currently in place and/or other initiatives being considered) without "radically changing" the HECO Companies' grid will adversely affect BOTH the renewable producer AND the rate payers. The solution is not to penalize the "as-available" renewable producers because the grids cannot take all their generation, the remedy is to "fix the grid." See Exhibit "D" attached hereto, at 9, § 4.2.

Additionally, failing to compensate generators directly and on a monthly basis for the correct amount of revenue losses they incur due to curtailment will lead to one of two consequences:

(1) The Commission will be required to design and authorize uplifts to be included in the FiT base rates for the curtailable generators. Even if the Commission were successful in accurately predicting the extent and costs of future curtailment episodes for all future FiT generating units over their entire operating life, the risk of ratepayers paying twice because of the FiT Program is very likely. The difference between the TPL proposed solution, and internalizing a curtailment adder into the FiT price, is one of efficiency and predictability. The latter will be inefficient because there will be generators who may never be curtailed, or would curtailed only for a limited period of time, and at the other end of the spectrum there will be others regularly exposed to curtailment.

(2) The Commission will decide not institute any form of compensation for curtailment to avoid the double payment issue. In this case, generators may submit to the Commission inflated development and operational costs in hopes of enjoying inflated FiT rates. If the Commission relies solely upon the developers' estimates in establishing the FiT rates, the ratepayer will be in the same situation as in (1) above. On the other hand, if the submitted information is ignored and the resultant FiT rates do not provide the required caution against curtailment losses, project risks will unacceptably increase. Under this second scenario, the increased costs to developers (who would be required to pay more to finance their projects) may result in FiT defaults.

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F. UTILITY AVOIDED COSTS MUST BE PROPERLY IDENTIFIED AND TRANSPARENTLY DETERMINED BEFORE A BALANCED, LEAST-COST DESIGN FiT PROGRAM CAN BE DEVELOPED IN HAWAII.

On the last day of the Panel Hearings, the Moderator focused on the lack of a record concerning the generic benefits in implementing a FiT Program. Tr. Vol. V, at 121, ln. 5-11. The moderator also requested from the parties their thoughts on revisiting the avoided cost concept to reduce potential gaps between forthcoming FiT rates and future utility avoided costs.

Since the enactment of PURPA in 1978, a voluminous body of literature and litigation material has accumulated on this subject. Without detailing this history, suffice it to say from a renewable energy procurement perspective, Federal Law (PURPA and subsequent FERC rulings and court decisions) advises its participants that determining avoided costs engenders two principles:

1. Avoided costs are comprised of all those costs which the utility would have incurred in the course of generating electric power (at its own facilities) instead of purchasing that amount of electric power from another utility or renewable energy generator; and
2. The items of avoided costs set forth in the immediately preceding sentence must be estimated on an incremental basis.

HECO's avoided cost practices and calculations violate both of the above principles, and consequently, avoided costs in Hawaii are severely depressed because:

1) No avoided cost components other than the energy commodity is considered. The calculated avoided costs of HECO and its operating companies are limited to only one component: the cost of generating the energy from its facilities. The ingredients ignored include the economic values of:

(a) The capacity the renewable energy facility is able to provide to the utility;

(b) The ancillary services the renewable energy facility could supply to the utility;

(c) Achievable greenhouse gas (GHG) reductions; and

(d) Potential reductions of criteria pollutants from utility plants.

Items (a) and (b) above fall within the category of avoided costs as defined by PURPA even though the utilities do not pay for them in Hawaii. However, the Commission previously rejected requests from generators for compensation of capacity their plants provided. In that regard, TPL respectfully requests the Commission revisit its decision because virtually every state having a credible renewable energy development program has ordered payment for capacity from firm and as well as variable (intermittent) resources, including wind. This shift to recognize the capacity value of intermittent generation is prompted by the significant advances in determining a fair and reasonable value for this service.[19] Methods for estimating potential ancillary services are also available.

Some may argue the above items (c) and (d) do not qualify as avoided costs because utilities do not pay for them in Hawaii. However, this is a short sighted view because eventually regulatory and/or market mechanisms will render fossil-fueled generation obsolete.[20] Proxy values for GHG and criteria pollutants reductions have been proposed and utilized in many parts of the U.S., and elsewhere. Furthermore, there are well-known techniques for assessing the value of emissions reductions through a damage-function approach. Consequently, until the Commission

[19] Michael Amelin, *Comparison of Capacity Credit Calculation Methods for Conventional Power Plants and Wind Power*, IEEE Trans. Power App. Syst., Vol. PAS-09, No. 24, pp. 685-691, May 2009. A copy of the same is attached hereto as Exhibit "E" and made a part hereof.
[20] See e.g., Energy Agreement

establishes a fair and reasonable methodology for estimating emission reduction credits, TPL recommends employing methodologies to gauge the societal value of investing in renewable energy resources.

2) HECO does not determine avoided costs on an incremental basis as mandated by PURPA.

As stated earlier, the HECO companies limit their estimates of avoided costs to the energy component only. The method they currently use is based on HECO's own interpretation of the Commission's decision in Docket 7310 which adopted a somewhat detailed yet incomplete description of a methodology for computing the avoided energy costs. This methodology was the result of a stipulation between interested parties without direct representation by independent power generators. Although it is unclear who engineered this effort, HECO's dominant role in Docket 7310 is undeniable due to the uncontested choice of its purchased production costing software package employed as the principal modeling tool for determining avoided energy costs. Moreover, the HECO companies consistently claim their calculations of avoided energy costs are based on the Commission's Docket 7310 order, but such assertion should be questioned and reviewed closely.

Thirdly, there are indications HECO's interpretation of the methodology adopted with his assistance violates the universally accepted requirement that avoided energy costs be estimated on an incremental basis. TPL is currently investigating the extent to which HECO is calculating avoided costs on an average basis. This effort has been hampered by a lack of timely information on the production modeling tools that HECO has been using for the process of computing avoided energy costs.

TPL appreciates these proceedings may not be the proper venue to raise issues rooted in other dockets. However, TPL has an obligation to alert the Commission and the parties to this proceeding that the current avoided cost practices in Hawaii may violated PURPA. Therefore, it is imperative the Commission revisit this stipulated methodology to ensure a proper estimate of avoided costs is employed in the FiT rates being considered in this Docket.

G. THIS FiT DOCKET PROCEEDINGS SHOULD BE FULLY INTEGRATED INTO THE CESP DOCKET PROCEEDINGS.

Mr. Carl Freedman of Haiku Design & Analysis "hit the nail on the head" when he recognized "from a systems planning perspective, . . . if we're really going to move forward to get 70 percent on this timetable, then there are things that's – those roadblocks are things that really need to get moving." Tr. Vol. IV at 98, ln. 21 to 99, ln. . "And my fear with the CESP is it's very – it's out there in future and it's an unknown." Id. at 99, ln. 3-4. Dr. El-Gasseir "second[ed] the concerns of Mr. Freedman, but . . . add[ed] for the purpose of regulatory efficiency and the limited resources that the parties have, [the Commission] may want to look at **accelerating the CESP because it really is very, very important.**" Id. at 99, ln. 15-19 [emphasis added].

The interrelationship between the CESP Docket and this FiT Docket was again raised on the last day of the Panel Hearings. In Panel VIII, Mr. Henry Q Curtis of Life of the Land followed up on Dr. El-Gasseir's understanding that a GE Study was performed to assess the impact of additional "as-available" generation upon the reliability of the HECO Companies grids ("GE Study"). Tr. Vol. V, at 106, ln. 9-15. In response to Mr. Curtis' request for a copy of the GE Study, Commissioner Kondo opined Mr. Curtis' "comments about getting all this information, **that seems to me to be the CESP docket**." Id. at 107, ln. 12-14 [emphasis added].

Based upon the above, it is evident the Commission should coordinate the proceedings in this FiT Docket with the CESP. Furthermore and as suggested by Dr. El-Gasseir, the Commission is recommended to introduce the FiT Program by way of the First Phase and accelerate the CESP to coincide with the first update of the FiT Program (i.e. Second Phase) in order to facilitate the transparency essential to determining whether the HECO Companies efforts to "improve the grid" are at the rate necessary to meet the goals set forth in the October 20, 2008 Energy Agreement Among The State Of Hawaii, Division Of Consumer Advocacy Of The Department Of Commerce And Consumer Affairs, And The Hawaiian Electric Companies ("Energy Agreement"). The next section of this Opening Brief will further detail the required aforesaid grid studies imperative to the successful implementation of the FiT Program and CESP.

H. PRESENT, PENDING, AND FUTURE INTEGRATED SYSTEM PLANNING STUDIES SHOULD BE A REQUISITE PART OF THIS FiT PROCEEDING UNDER CONDITIONS THAT ENSURE MAXIMUM TRANSPARENCY AND INDEPENDENCE OF STUDY CONDUCT.

Proper design and implementation of cost-effective FiT programs for the Islands require carrying out comprehensive Integrated System Planning Studies for each HECO service territory. Moreover, because of inherent and unavoidable conflicts of interest, it is essential that the desired studies be carried out by outside experts without any vested interest in the outcome of the results and under independent management without any ties to any Party to the FiT Docket, including the HECO companies. The narrative presented below summarizes TPL's experience as it tried to have access to HECO-sponsored and/or initiated system planning studies. This experience confirms the unquestioned need for independence and transparency even if one is to pretend that the utilities do not have a vested interest in the outcome of the required analyses and planning.

Dr. El-Gasseir mentioned during Panel VIII there existed "a study that was done by

General Electric, very recent study" of the grid penetration and limitations of the HECO Companies ("GE Study"). Tr. Vol. V, at 103, ln. 24 to 104, ln.1 . In The HECO Companies' Submission Of Supplemental Information filed herein on May 8, 2009 (the "HECO Supplemental Information"), Dr. El-Gasseir's statement concerning the GE Study was confirmed. See HECO Supplemental Information, at page 4, Section IV. "The electrical systems are being analyzed in various studies conducted by General Electric for the utilities." Id. Assuming properly designed and tasked, the findings, conclusions, and recommendations of these studies will contain essential information required for the Commission to "make a sound and informed decision in this docket." HECO Supplemental Information, at 2. Phase 1 of those studies will "establish a baseline condition" of the existing infrastructure of the grid. Id. at 4. "Phase 2 will analyze the technical and economic impact of infrastructure expansion scenarios (more renewable energy and possible mitigation technologies) relative to the baseline condition. Id. at 5.

In another effort to obtain information pertinent to this proceeding, TPL had to reiterate its request for the Electric Power Systems, Inc. Report referenced by the HECO Companies in their response to TPL-IR-11, subpart e ("Electric Power Report"), by way of its Submissions Of Information filed herein on May 8, 2009 ("TPL's Submissions"). See TPL's Submissions at 10-12. Pursuant to an oral request made by some of the Intervenors, the HECO Companies attached the same as Appendix C to the HECO Supplement Information. As acknowledged by the HECO Companies, the Electric Power Report "provides important information regarding the issues associated with integrating intermittent renewable resources on an island grid." Id. at 8. However, Phase II of the Electric Power Report which relates to the HELCO grid is void of any value to assist the Commission in designing and implementing a viable FiT Program to meet the goals of the Energy Agreement (the "Phase II Report"). See Exhibit "F" attached hereto and made a part hereof.

One (1) of TPL's Expert Witnesses, Mr. Harrison Clark, closely examined the Phase II Report. Id. In doing so, Mr. Clark found numerous glaring deficiencies therein which readily place into question its usefulness. First, no appendices to the Phase II Report were provided by HECO severely hindering a comprehensive and critical analysis of the same. Id. Substantively, the Phase II Report does not include the re-powered Keahole Generating Plant which should greatly improve the Big Island's grid stability and system reliability. Id. Failure of the Phase II Report to account for the Keahole generation renders its findings and conclusions of no benefit to amnyone. Id. Thirdly, the analysis of the Kamao'a Wind Farm in the Phase II Report is inaccurate and misleading. Id. Specifically, "oscillations in frequency following load shedding suggest a **significant modeling problem with the generator governors, not a system problem** that must be addressed by increasing the amount of thermal generation on-line." Id. In summary and as succinctly stated by Mr. Clark, the Phase II Study "provides virtually no useful insight into the behavior or limitations of the HELCO system to accommodate renewable generation. Id.

III. CONCLUSION:

The evidence presented by TPL herein clearly disputes the mistaken belief that wind generation is "unpredictable and unstable." As noted in other foreign countries, wind generation is utilized as "spinning reserves" on their grids. Moreover, the advancement in technology and design of wind turbines places them in the fore-front of as-available renewable generation in the World's Green Economy. Therefore, a properly designed FiT Program necessitates the integration of wind generation as an essential component to achieve the laudable goals of the

Energy Agreement.

Secondly, a successful FiT Program will require the Commission to address the "curtailment problem" that presently exists, especially with the HELCO system. It would undermine the FiT Program if existing IPPs are "penalized" at the expense of new renewable generation entering into the grid under that program. Therefore, adoption of the DNH Formula into the FiT Program will both improve the success of it, and reduce the burden on system operators to identify which generators would need to be curtailed to ensure system reliability and grid stability.

Finally, the last component of a successful FiT Program would include the Initial Phase to gather valuable information and gain experience concerning the behavior of entrants thereto, and utilization by ratepayers of the generation therefrom. In effect, the questions would be whether the Initial Phase design attracts sufficient interest in the FiT Program by renewable generators, and whether the ratepayers would modify their behavior because they utility bills will be higher due to the anticipated FiT Rate being more than the utility's avoided cost.

Respectfully submitted.

DATED: Honolulu, Hawaii, June 12, 2009.

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April 8, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, Room 103
Honolulu, HI 96813
Attn: Stacy Kawasaki Djou, Esq.

Re: Docket No. 2008-0273 – In the Matter of Public Utilities Commission Instituting a Proceeding to Investigate the Implementation of Feed-In Tariff: Curricula Vitae of Tawhiri Power LLC's Expert Witnesses

Dear Commissioners and Commission Staff:

Pursuant to Chairman Carlito P. Caliboso's letter dated April 7, 2009, attached please find the Curricula Vitae of the Expert Witnesses for Tawhiri Power LLC.

If you have any questions regarding the above, or enclosed, please feel free to contact the undersigned. Thank you for your assistance with this matter.

Very truly yours

Harlan Y. Kimura

Attachments

cc: Service List (w/ attachment)
Tawhiri Power LLC (w/ attachment)

EXHIBIT "A"

Mohamed El-Gasseir, Ph.D.

April 2009

Principal Areas of Expertise

- Developing methodologies for seamless integration of pricing and investment programs for distributed resources, self-generation, feed-in-tariffs and Qualifying Facilities
- Distributed resources and self-generation planning, assessment and policy analysis
- Configuration and assessment of high-voltage dc and ac transmission systems integration applications
- Simulation and analysis of failure modes, repair cycles and outage damage functions
- Purchase-power agreements (PPAs) contracting and due diligence applications
- Renewable power market assessments and project development
- Stochastic price forecasting for risk management and bid evaluations
- Developing transmission access for renewable resources
- Identification and assessment of on-site generation investment opportunities
- Integrated (generation and T&D) cost effectiveness studies of generation investments in central power plants, distributed resources and DSM alternatives

Employment History

2006–Present Rumla Engineering Consultations & Technical Services, Inc., Principal

2003–Present DC Interconnect, Inc., Principal

1992–Present Rumla, Inc., Principal

1991 - 1992 Barrington-Wellesley Group, Senior Associate

1988 - 1989 Mechanical Engineering Department, University of California, Berkeley, Lecturer

1981 - 1991 Independent energy consultant

1978 - 1981 Lawrence Berkeley Laboratory Energy Program, Research Assistant/Associate

1976 - 1977 U.S. Council on Environmental Quality and National Academy of Sciences Committee on Nuclear and Alternative Energy Systems, Consultant

Academic Background and Professional Associations

- Ph.D. in Energy and Resources, University of California at Berkeley (1986)
- M.S., Chemical Engineering, University of Rochester, New York (1974)
- B.Sc., Chemical Engineering, University of California at Berkeley (1972)
- AAAS, ACEEE and IEEE member

Sample Conducted Courses and Industry Seminars

- "Staff Workshop to Review Analysis of the Self-Generation Incentive Program", California Energy Commission, Sacramento, California, September 3, 2008
- "Emerging Grid Reliability Improvement Technologies and Their Control Requirements", Power Grid Europe Conference, Milan, Italy, June, 2008
- "Emerging HVDC Technologies, Controls and Applications", Power Grid Europe Conference, Madrid, Spain, June 26-28, 2007
- "Experience with MAPS Modeling for Post-MD02 California Markets", GE MAPS Users Conference, Washington D.C., October 16-17, 2003
- "Analyzing the Potential for Price Spikes", Workshop for the Electric Power Industry, Washington, D.C., March 26, 1999
- "Distributed Generations: Assessing High-Value Utility Applications", First EPRI Workshop on Distributed Generation, New Orleans, Louisiana, September 1992
- Engineering 160 (course): Basic Thermodynamics and Energy Conversion Processes, University of California, Berkeley

Selected Publications, Reports and Conference Presentations

"Identification and Mitigation of Weak Buses & Transmission Corridors and Evaluation of Performance Improvements versus Mitigation Measures Costs of Large Interconnected Transmission Grids", EPRI, Palo Alto, CA and DCI, Vancouver, B.C., Canada, 2009

Cost-Benefit Analysis of the Self-Generation Incentive Program, October 2008, CEC-300-2008-010-F, http://energy.ca.gov/2008publications/CEC-300-2008-010/CEC-300-2008-010-F.PDF

"The Application of Segmentation and Grid Shock Absorber Concept for Reliable Power Grids", Middle East Power Conference, MEPCON, March 2008

"Softening the Blow of Disturbances: Segmentation with Grid Shock Absorbers for Reliability of Large Transmission Interconnections", M.M.El-Gasseir, et al., *IEEE Power & Energy Magazine*, Jan/Feb 2008, pp 30-41

"Emerging Grid Reliability: Improvement Technologies: A Perspective on Segmentation, the Grid Shock Absorber Concept, and Competing Technologies." EPRI, Palo Alto, CA and DCI, Vancouver, B.C., Canada: 2007, 1013996

"Intermittency Analysis Project", Final Report, Prepared by the Intermittency Analysis Team (Rumla, Inc. et al) for the California Energy Commission PIER Program, July 2007

"Feasibility of using HVDC Technology for Reinforcing the Interior to Lower Mainland Transmission Grid", DC Interconnect Report Prepared for BCTC, June 2007

"Assessing System Benefits of Renewable Trunkline Transmission Projects", Consultant Report Prepared for the California Energy Commission, December 2006

"Technical Assessment of Grid Shock Absorber Concept", EP-P20414/C9939, DC Interconnect Report, July 2006

"Potential Impacts on Long-Term Zonal-Contracts from the Amended Market Design as Proposed in the July 22, 2003 Filing of the California Independent System Operators before the Federal Energy Regulatory Commission", Confidential Draft Final Report, prepared for the California Energy Resources Scheduling Division, California Department of Water Resources, July 2, 2004

"Transmission Planning for an Industry in Transition – The Schizoid Environment of Transmission Investments Planning", Transmission Expansion and Systems in Transition Conference, Miami, FL, February 8, 2002

"Transmission Planning for an Industry in Transition – Towards Comprehensive Regulatory and Market Reforms for a More Efficient Power Industry", Transmission Expansion and Systems in Transition Conference, Miami, FL, February 8, 2002

"Review and Analysis of Administrative Charge Practices of Independent System Operators", Prepared for Independent Electricity Market Operator of Ontario, Canada, Final Report, May 15, 2001

"The Role of Transmission Pricing & Management in Precipitating the Current Crisis in California & Prospects for Reform",

Transmission Grid Expansion and System Reliability Conference II: Focus on Pricing, May 24, 2001, Denver, Colorado

"California's State Takeover of Transmission Assets", Transmission Grid Expansion and System Reliability Conference I: Focus on Regulation, May 21, 2001, Denver, Colorado" The Problems of Modeling Transient Energy Markets", Electricity Market Pricing Conference, Vail, Colorado, August9-10, 1999

"Transmission Development in the U.S. and Implications for Canadian Providers", Electricity '99 Conference, Canadian Electric Association, Vancouver, B.C., March 29, 1999

"Working with Transmission Loading Relief (TLR) to Prevent Future Supply Problems and Relieve Congestion on the Grid", Infocast Workshop Conference on Congestion Management, Washington, D.C., March 25, 1999

"Implications of Super-ISOs for the Business Strategies of Power Market Players", Infocast Conference on Congestion Pricing & Tariffs, Washington DC, September, 1998

"System Operation Models for an Open Market: A Framework and Alternative Study", presented at the Annual Brazil Utilities Conference, Brazil, May 1998

"Atlantic City Electric Company Audit of Stranded Costs: Final Report", with Barrington-Wellesley Group, prepared for New Jersey Board of Public Utilities Docket No. EO97979456, December 1997

"Access Fee Consolidation Proposal for the Western Interconnection", presented at Western Regional Transmission Association, Salt Lack City, July 1997

"Distributed Technologies Characterization And Assessment Phase Two Report: Assessing Local Area Integrated Planning of Distributed Generation, Storage and Demand Side Management Investments for Deferring Planned Distribution System Upgrades", prepared for Detroit Edison Company, December 1995

"Dispatchable Distributed Generation Characterization And Assessment For Long Island Lighting Company", prepared for the Long Island Lighting Company, November 1995

"DISTRIBUTED GENERATION: Implications for Restructuring the Electric Power Industry", Public Utilities Fortnightly, June 15, 1995

"Distributed Generation Characterization and Assessment for San Diego Gas & Electric", prepared for the Electric Power Research Institute (EPRI), October 1994

"Distributed Resources Assessment in the Service Territory of Anza Electric Cooperative", prepared for the Electric Power Research Institute (EPRI), October 1994

"Distributed Generation Assessment for Azienda energetica municipale of the City of Milan—Phase I: Siting and Technology Screening for High Value Applications", prepared for the Electric Power Research Institute (EPRI), October 1994

"Distributed Generation Assessment Guidelines—A Market-Based Framework for Evaluating High-Value Applications", prepared for the Electric Power Research Institute, December 1993

"Distributed Generation Assessment, Evaluation, and Practice Program—Dis-Gen Practice", prepared for the Electric Power Research Institute (EPRI), November, 1993

"Assessment of the Benefits of Distributed Fuel Cell Generators in the Service Areas of Central & South West Services, Inc.", prepared for EPRI, October 1993

"Carbonate Fuel Cells and Diesels as Distributed Generation Resources—Economic Assessment of Application Case Studies at Oglethorpe Power Corporation", prepared for the Electric Power Research Institute (EPRI), October 1993

"Molten Carbonate Fuel Cells as Distributed-Generation Resources: Case studies for the Los Angeles Department of Water and Power", prepared for EPRI, May 1992

"Recent Developments Affecting Canadian Energy Exports to California and Other U.S. Markets", presented at the North American Electric Power Generation Demand for Canadian Natural Gas in the 1990s Conference, November 1991

"Need Assessment of the Tondu Cogeneration Facility", Independent Power Corporation, Testimony before the Michigan Public Service Commission, December 23, 1986

"Long-Term Projections of Avoided Energy Costs" for Pacific Gas and Electric Company, Independent Power Corporation, Prepared for Combustion Engineering Inc., Dec. 12, 1986

"Analysis of the Cost Competitiveness of Coal-Fired Electric Generation vs. Purchase Power" for the Arizona Electric Power Cooperative, Independent Power Corp., Nov. 1986

"Brief of the Nevada Mining Association, Before the Public Service Commission of Nevada", Docket No. 86-701, October 23, 1986

"Supplemental Testimony of Independent Power Corp. on behalf of the Nevada Mining Assoc., before Public Service Commission of Nevada", Docket No. 86-701, Sept. 22, 1986

"Testimony of Independent Power Corporation on behalf of The Nevada Mining Association, Before the Public Service Commission of Nevada", Docket No. 86-701, September 10, 1986

"Pacific Gas and Electric System Operation Characteristics and Effects on Geothermal Steam Prices and Revenues", Prepared for Graham & James, July 22, 1986

"Baseline Projections of Avoided Energy Costs and Incremental Energy Rates for California's Investor Owned Utilities", prepared for Pacific Lighting Energy Systems, June 17, 1986

"General Assessment of Trends in Cogeneration Fuel Prices, Avoided Costs and Retail Electric Rates of Pacific Gas & Electric Co. 1986-2000", for Chevron USA, April 11, 1986

"Projection of the Likely Range of Incremental Energy Rates and Avoided Energy Costs of Pacific Gas & Electric Company", prepared for Signal Capital Corporation, October 22, 1985

"Projected Prices for Pacific Gas & Electric Co. Geothermal Steam at the Geysers 1986-2000", Independent Power Corp., for Kidder, Peabody & Company, October 18, 1985

"Initial Assessment of the Avoided Energy Costs of Pacific Gas and Electric Company and Southern California Edison", for Power Systems Engineering, Inc., September 10, 1985

"Review of California Utility Fuel Price Forecasts", for Signal Capital Corp., Sept. 5, 1985

"Projected Prices for Pacific Gas & Electric Company Geothermal Steam at the Geysers 1986-1995", Independent Power Corp., for Chevron Resources Company, August 29, 1985

"Desk-Top Computer Modeling for Electric Utilities; A Survey of Hardware/Software Compatibility", SERA Report No. 85-190, January 1985

"Tension Leg Inservice Non-Destructive Examination System Phase II Reliability Study: Reliability and System Effectiveness Assessment", Final Report to Sigma Research Inc. /Conoco U.K. Ltd., SERA No. 84-181, November 1984

"Review of Centaur G Prime Reliability Analyses for the Radioisotope Thermo-electric Generator (RTG) Safety Study for the Galileo and International Solar Polar Space Mission: Addendum to Review of Shuttle/Centaur Failure Probability Estimates for Space Nuclear Mission Applications", Report for Teledyne Energy Systems, Inc./Air Force Weapons Laboratory, SERA No. 84-146, September 1984

"Review and Analysis of the Nevada Power Company 1984-2004 Resource Planning Submittal" Report to the Public Service Commission of Nevada and the Nevada Office of Consumers' Advocate, SERA No. 84-155, August 1984

"Review and Evaluation of the Sierra Pacific Power Company 1984-2004 Resource Planning Submittal", Report to the Public Service Commission of Nevada and the Nevada Office of Consumers' Advocate, SERA No. 84-152, August 1984

"Analysis in Support of Assessment of BPA's Short Term Rates and Load Balances", SERA, Inc., Report to Southern California Edison, SERA No. 84-126, March 1984

"Electric Utility Demand Forecasting and Resource Planning in Nevada: A Review of State-of-the-Art Methods and Recommendations for Regulatory Oversight", Dec. 1983

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"An Analysis of the WPPSS 3 Delay Decision by the Bonneville Power Administration", Report to the Southern California Edison Company, SERA No. 83-85, August 1983

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Harte, J., et al., Environmental Consequences of Energy Technology: Bringing the Losses of Environmental Services into the Balance Sheets, Part II: Services, Disruptions, Consequences, (Energy and Resources Group, Univ. of California, Berkeley, ERG-WP-77-2, October 1977)

Testimonies:

Performance audit on post-restructuring purchase power practices of Pacific Gas and Electric Power Company for the California Public Utilities Commission (CPUC) (testimony before the CPUC), 2001

Evaluation of IOU-proposed transmission loss factor estimation techniques based on the ISO's Generator Meter Multipliers methodology (testimony before the CPUC), 2000

Development of auction strategies and rules for procuring wholesale Standard Offer service to meet customer-load obligations of New England investor-owned utilities (testimony support before the Department of Energy and telecommunications of Massachusetts), 1999

"Atlantic City Electric Company Audit of Stranded Costs: Final Report", with Barrington-Wellesley Group (testimony support before the New Jersey Board of Public Utilities Control), 1997

Designing rules and regulations governing utility purchases of independently generated power and developed contract language for standard offers to qualifying facility projects (CPUC testimony), 1993

Evaluation of U.S.-Canada Free Trade Agreement impacts on power trade (testimony before California legislature), 1993

Development of methodologies for forecasting available transfer capability on the Pacific AC Intertie transmission system and associated impacts of inter-regional surplus power trade (testimony before the California Energy Commission), 1989

Assessing prospects for financing and construction of the California-Oregon Transmission Project and the Third AC Intertie (California Energy Commission testimony), 1988

Contract performance evaluation of major utilities involved in a long-term multi-lateral agreement for the sale, exchange and banking of electricity (litigation support), 1987

"Review and Analysis of the Nevada Power Company 1984-2004 Resource Planning Submittal" (testimony before the Public Service Commission of Nevada), 1984

HARRISON K. CLARK, Consultant

Mr. Clark received the BSEE degree from California State Polytechnic University (Cal Poly), San Luis Obispo, CA in 1966. He joined General Electric that year and over the next four years completed several graduate level courses including the GE "A Course" while performing conceptual design, power flow, stability, and protection studies for GE's largest paper, chemical, and petroleum clients.

In 1970 Mr. Clark joined Power Technologies, Inc. (PTI). His work at PTI included equipment failure analysis, transmission planning, blackout investigations and criteria development. He helped guide development of the PTI PSS/E stability program and has analyzed stability and voltage collapse problems and developed protection philosophy and solutions to overvoltage, loss-of-synchronism, and self-excitation problems.

His transmission planning work has involved all voltage levels and all of the available techniques for maximizing transfer capability including re-closing, series capacitors and reactors, shunt compensation, braking resistors, unit tripping, stabilizers, fast valve actuation, high performance excitation systems and remedial action schemes. He developed new extensions to digital governing on hydro plants in Alaska, including novel use of Pelton turbine deflectors for both stability and rapid black-out recovery.

Mr. Clark's early industrial experience allowed him to make significant contributions to electric power industry efforts to improve simulations of customer loads in first-swing, oscillatory and voltage stability analysis. Models he developed include induction motor dynamics, discharge lighting, magnetic saturation, and the effects of manual and automatic load controls such as thermostats. He developed QV analysis and other analytical methods and solutions to voltage collapse, as well as criteria to control risk of voltage collapse. He was an invited presenter at the first joint NSF/IEEE/EPRI Conference on Voltage Stability in 1988 and has made many subsequent presentations at WSCC, IEEE, and EPRI events.

He investigated nine major blackouts including the 1977 New York City blackout. This experience led to development of transmission planning and operating criteria for clients in Canada, the U.S., Norway, and Central America. He has presented expert testimony in legal proceedings in Canada and in both State and Federal proceedings in the U.S.

Mr. Clark has taught PTI Short Courses on System Dynamics, HVDC, and Static Var Systems and portions of the two-year Power Technology Course. He created the PTI Voltage Stability Course, presented to over 1000 students world-wide. He was a major contributor to EPRI's first operator training course.

At PTI Mr. Clark was promoted to Senior Engineer in 1974; Manager, Utility System Performance in 1984; and Manager, Western Office in 1987. He is a Senior Member of IEEE and has presented or published 43 papers and articles: Mr. Clark retired from PTI in 1996 and is now an independent consultant. In 1977 he was selected by BPA to serve on the Blue Ribbon Panel assembled to guide BPA in addressing major 1996 WSCC disturbances.

Recent activities include contributions to the Western Governor's Association August 2001 report "Conceptual Plans for Electricity Transmission in the West," several testimony assignments, assistance to a industry leading consulting firm on several voltage stability analyses, and assistance to clients in the Northeast following the August 14, 2003 blackout.

March 2008

Harrison K. Clark 8261 Berg Street Granite Bay CA 95746 www.hkclark.com 916 791-2284

Publications

1. "Load Shedding for Industrial Plants," Paper No. ICP-WED-PM2 725, presented at Eighth Annual Meeting of IEEE Industry Applications Society, October 8-11, 1973.
2. "Voltage Control in a large Industrialized Load Area Supplied by Remote Generation," Paper No. A 78 558-9, presented at IEEE PES Summer Meeting, July 17, 1978, (co-authors, T.F. Laskowski, A. Wey filho, and D.C.O. Alves).
3. "Transient Stability Sensitivity to Detailed Load Models: A Parametric Study," Paper No. A 78 559-78, presented at IEEE PES Summer Meeting, July 17, 1978, (co-author, T.F. Laskowski).
4. "Considerations in the Evaluation of Series and Shunt Compensation Alternatives," presented at the T&D Expo, Chicago, IL, May 14-16, 1985.
5. "Microprocessor Based Load Shedding for Industrial Plants," presented at the IEEE Industry Applications Society I&CPS Conference, Cleveland, OH, May 5-8, 1986.
6. "Enhancement of AC Systems by Application of DC Technology," EPRI Transmission Limitations Panel, IEEE-PES Winter Meeting, New Orleans, LA, February 2-6, 1987, and presented at the Symposium on Electrical Operational Planning, Rio de Janeiro, Brazil, August 17-21, 1987, (co-author, F.P. de Mello).
7. "Modeling to Define Limits to Shunt Compensation Use," Panel on Reactive Modeling Considerations, IEEE-PES Winter Meeting, New Orleans, LA, February 2-6, 1987.
8. "Voltage Control and Reactive Supply Problems," IEEE Tutorial Course: REACTIVE POWER: BASICS, PROBLEMS AND SOLUTIONS, Publication 87 EH0262-6-PWR, presented at the IEEE-PES Summer Meeting, San Francisco, CA, July 12-17, 1987, and the Winter Meeting, New York, NY, 1988.
9. "Dynamic Aspects of Excitation Systems and Power System Stabilizers," presented at the Symposium on Electrical Operational Planning, Rio de Janeiro, August 17-21, 1987, (co-authors, F.P. de Mello and L.N. Hannett).
10. "Re active Compensation in Power Systems," presented at the Symposium on Electrical Operational Planning, Rio de Janeiro, August 17-21, 1987, (co-author, D.N. Ewart).
11. "Micro processor Based Load Shedding for the Pulp and Paper Industry," TAPPI Annual Meeting, New Orleans, LA, September 1987, and TAPPI JOURNAL, December, 1987.
12. "Industrial and Coge neration Protection Problems Requiring Simulations," IEEE Transactions on Industry Applications, Vol. 25, No. 4, July/Aug. 1989 (co-author, J.W. Feltes).
13. " The Case for Asynchronous Interconnection of China's Electrical Systems," presented at the Joint IEEE/CSEE Conference on High Voltage Transmission Systems in China, Beijing, The Peoples' Republic of China, October 17-22, 1987, (co-author, L.O. Barthold).
14. "Load Modeling for Power Flow and Stability Studies," presented at the 1988 WSCC Stability Seminar, Rosemead, CA, April 5-7, 1988.
15. "Voltage Control and Reacti ve Supply Problems," presented at the 1988 WSCC Stability Seminar, Rosemead, CA, April 5-7, 1988.
16. "Voltage Contro l Practices in North America," IEEE/NSF/EPRI Conference: Bulk Power System Voltage Phenomena--Voltage Stability and Security, Potosi, Missouri, September 19-24, 1988, Proceedings: EPRI Publication EL-6183.
17. "Experience with Load Models in the Simulation of Dynamic Phenomena," Panel on Load Modeling Impact on System Dynamic Performance, IEEE-PES Winter Meeting, New York, NY, January 30 - February 3, 1989.
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Reactive Planning and Voltage Collapse Experience

While performing planning studies for the greater Sao Paulo area in 1973, Mr. Clark recognized the potential for low voltages, motor stalling, and system break-up for certain contingencies. He coined the term "voltage collapse" and proceeded to confirm the problem through simulations using detailed load models. He developed QV curve analysis to help define reactive requirements. Two large synchronous condensers were installed to reduce risk of voltage collapse. Mr. Clark also recommended the first ever use of undervoltage load shedding. This was a landmark effort in that it defined the nature of the voltage collapse problem, provided terminology and tools to address it, and developed solutions. Shortly after this effort Mr. Clark was instrumental in PTI's development of the industry's first long-term simulation capability for the study of the "slow dynamics" of voltage collapse.

Mr. Clark went on to conduct numerous reactive planning and voltage collapse studies. He refined the concept of undervoltage load shedding and demonstrated its effectiveness in several long-term simulation studies for clients facing voltage collapse problems. He contributed to all early IEEE tutorials and working group efforts to define the voltage collapse problem and it's analysis and solutions. He was a frequent speaker at EPRI, NSF and WSCC Seminars on the Voltage Collapse problem.

In 1986 Mr. Clark prepared the PTI "Voltage Course" which covered reactive planning and in particular the nature of the voltage collapse problem and it's analysis and solutions. This course reached more than 1000 students in several dozen countries.

In 1991 Mr. Clark helped Central Power and Light understand an incident on their system (Corpus Christie and southward) that involved "transient voltage collapse" wherein motors slow sufficiently during a fault that the system is unable to re-accelerate them. This same effort also revealed a traditional voltage collapse problem in the Brownsville area near the Mexican border.

In addition to his early IEEE contributions, Mr. Clark has written articles on the voltage collapse problem and on voltage criteria requirements. He has regularly advised clients that voltage problems will be overlooked if studies are limited to the contingencies normally associated with thermal and angular stability criteria.

Blackout Analysis Experience

Mr. Clark's successful career in the planning of reliable transmission systems has been in part the result of first-hand experience with system failures. His investigations of blackouts and major disturbances have equipped him to prepare effective reliability criteria and ensure that those criteria are adequately applied.

WSCC 1996. Mr. Clark was appointed to the Blue Ribbon Panel formed to examine the two 1996 events that caused WSCC break-up and widespread loss of load. He was one of three experts on the panel with reactive planning and voltage stability experience. He prepared a dissenting opinion letter which was published with the Panel Report.

Southern California 1996. One of the two 1996 WSCC-wide events cascaded into angular instability and voltage collapse in a large area of Southern California. Mr. Clark investigated these events and their impact on large industrial customers.

Hawaii 1992. Line outages resulted in unexpected generating plant responses and blackout. Governor overspeed protection caused power swings and voltage regulators on manual control allowed voltage to collapse. Mr. Clark recommended tests and operating practices to reduce the risk of such surprises in the future.

Saudi Arabia 1990. Angular instability that caused blackout was traced to inadequate protection of EHV lines.

Central America 1996. In a study to improve reliability in six of the seven countries of Central America, Mr. Clark reviewed recent disturbances and guided the development of system upgrades and an interconnection to improve reliability and economic operation.

New Jersey 1974. A medium voltage substation burn-down resulted in extended outages to area customers. Mr. Clark examined the substation physical and protection design and found unprotected bus sections. Major protection updating was required to ensure detection of all faults.

New York City 1977. Mr. Clark assisted the New York Public service commission in its analysis. His operator interviews and related work revealed several important issues that were overlooked by other investigators. He prepared the NY Power Commission's list of questions for Consolidated Edison, and assisted in the analysis of the response. He subsequently supervised analytical work conducted by Consolidated Edison to improve reliability.

Venezuela 1978. A country-wide blackout occurred during a visit by US President Carter. Mr. Clark was a member of a two-man team that spent one month reviewing all Venezuelan planning and operating practices. The team prepared a document that included 23 specific recommendations that would reduce the likelihood of future major outages. President Perez of Venezuela ordered the utilities to implement all 23 recommendations.

St. Johns Newfoundland 1985. System experience and the prospect of greatly increased imports lead to analysis of major disturbances and future reliability. Mr. Clark conducted these analyses and prepared both new planning and operating criteria for the Province and an application guide for the new criteria. He prepared similar criteria for Norway.

USA Midwest 2003. Assistance to certain entities in the Midwest and east subsequent to the 8/14/2003 northeast blackout. Includes advice and training of engineering and operations personnel.

Testimony Experience

In addition to the experience covered in the biography, Mr. Clark has provided expert witness services on occasions as listed below:

Deposition on causes of failure of protection to prevent energization and destruction of the generator of a 400 MW thermal plant during maintenance. Litigation was between the plant owner (Utah Power and Light) and the architect/Engineer responsible for plant and switchyard design.

Extensive testimony on the technical feasibility of planning and operating a 1400 km HVDC transmission system extending from the Churchill Falls plant on the Quebec-Newfoundland border to St. Johns Newfoundland. Testimony addressed steady state and dynamic performance of the line and receiving system. Newfoundland would receive up to 50% of its power from this line. Testimony was on behalf of Newfound Labrador Hydro in action against Hydro Quebec.

Testimony before the Wisconsin Public Service Commission on behalf of Wisconsin P&L and Exxon on the limitations to use of shunt capacitors and static var controllers to extend the capacity of an existing 115 kV system and thereby delay the need for a 345 kV line.

Extensive testimony before the Utah Public Service Commission on behalf of the Utah Association of Municipal Power Cooperatives. UAMPS wished to construct a transmission line from Central Utah to Southwest Utah and Nevada. The testimony focused on the greater ability of the Associations proposed line to serve Southwest Utah reliably and without jeopardizing stability of the greater Utah system as compared to a line proposed by Utah Power and Light.

Testimony before the United States Federal Energy Commission Staff on behalf of Dayton Power and Light in a dispute between DP&L and the City of Piqua over extent and type of interconnection that is

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needed to improve reliability of power supply to Piqua. Effort included visits to substations and lines, review of Piqua and DP&L operating practices, staff quality, and other factors affecting interconnected operation.

Depositions, testimony, and rebuttal testimony before FERC and the Texas Utility Commission in support of the merger of Central and Southwest and El Paso Electric Company.

Testimony before ALJ and a Commissioner of the California Public Utilities Commission regarding use of the ISO generation meter multipliers (GMMs) for the purpose of quantifying loss savings associated with QF power deliveries.

Testimony on behalf of the CPUC's Office of Rate Payer Advocates concerning SDG&E's application for the 500 kV Valley-Rainbow project.

Protection Experience

Mr. Clark's protection experience includes a full year as a relay requisition engineer with General Electric in the medium voltage switchgear department in 1966. In that position he was responsible for preparation for protection equipment design to meet industrial and utility customer specifications. Responsibilities included assembling the necessary complement of relays, laying out the relay panels, and preparing elementary diagrams for the relays, batteries, and breaker trip and close circuits.

For three years (1967-1970) he worked as an application engineer in the GE Industrial Power Systems engineering unit in Schenectady. In this assignment he conducted system analysis and relay application and coordination studies for large paper mills, steel plants, and refineries. The protection studies included utility interconnection protection, coordination with utility relaying, etc.

Mr. Clark joined PTI in 1970, and for several years continued to conduct studies of industrial power systems with heavy emphasis on protective systems. He was solely responsible for relay selection and settings in the 200 MW isolated power system (240 V through 13.8 kV) of the Amerada Hess refinery in the Virgin Islands, and continues to consult with Amerada Hess today.

In the mid 1970's his responsibilities shifted to EHV planning. In transmission planning and design studies for clients in South America he was frequently responsible for recommending protective systems for special situations, including compatibility with existing protective systems, out-of-step blocking and tripping in systems subject to instability, overvoltage protection for systems subject to radial load rejection and self-excitation, comparison of reliability of blocking and unblocking directional comparison schemes where sympathetic line trip was a special problem, and others. One study required development of a detection scheme for impending self-excitation based on generator terminal overvoltage and negative field current relays.

Mr. Clark assisted the New York Public Service Commission in its investigation of the 1977 New York City blackout, including the role of protection in the cascading process. He identified 7 relay problems that contributed to the cascading or delayed restoration. In 1978 he was the coauthor of a report on a country-wide blackout in Venezuela. The report included 23 recommendations to reduce risk of future similar occurrences, six of which addressed relay problems that contributed to cascading and restoration problems.

In 1978 he investigated a major substation burndown that was traced to a fault that was in a gap between first zone protection zones, and which interrupted trip circuits of backup protection thereby preventing clearing.

In 1979 he conducted an extensive dynamics study to specify a protection system for the Guri 800 kV system in Venezuela. This coordinated protective system addressed stability and cascading problems with out-of-step block and trip relays, overvoltage relays, and a unit tripping scheme.

He conducted failure modes and effects analysis on a complete nuclear station auxiliary system, including protection, battery systems, and automatic controls for starting of diesels and emergency coolant drives.

Since 1983 he has conducted a number of cogeneration protection studies, including voltage levels from 480 volts through 138 kV. In 1985 he conducted a coordination study for the Electric Boat Division of General Dynamics facility in Connecticut. This study covered over 400 protective devices from 220 volts through 69 kV.

He analyzed the protective equipment and circuitry that failed to prevent catastrophic damage to a large generating unit when it was accidentally energized from the EHV system. He provided testimony during litigation that followed this incident.

In 1984 and 1985 he investigated two breaker failure disturbances for a midwest client, both traced to relay problems at 69 and 230 kV. Problems included wiring errors and inappropriate relay settings.

In 1986 Mr. Clark also investigated the protection problems that could result from the operation of two parallel 300 kV lines with existing shield wires removed. These lines are in an area where tower footing resistance ranges from 20 to over 250 ohms. Various relay options, including wave relays were considered.

In 1986 he also documented potential fault level, grounding, and protection problems associated with cogeneration on distribution systems for a client, and reviewed six planned cogeneration interconnections for the same client.

In 1987 he investigated a 1986 disturbance in the Orange and Rockland system and identified from oscillographs and simulations a number of relay problems including sympathetic trip and out-of-step tripping.

Mr. Clark prepared the Power Technology Course unit on protection and taught this unit for 17 years. His course notes for the unit are used in the graduate program at the University of Sao Paulo. He has written papers on industrial plant load shedding and on microprocessor based industrial load shedding. He co-authored a paper on interconnection protection problems associated with customer owned generation and system dynamics for the annual IEEE-IAS meeting in 1986.

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A Mighty Wind

March/April 2009

J. Charles Smith, Robert Thresher, Robert Zavadil, Edgar DeMeo, Richard Piwko, Bernhard Ernst, and Thomas Ackermann

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In the spring of 2008, the U.S. Department of Energy released a report titled "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply." The report examined a scenario for producing 20% of the country's electrical energy supply from domestic wind energy resources, a level that has already been reached in some parts of Europe. While installing 300 GW of wind energy by 2030 would require changes to traditional business practices, the scenario was found to be feasible. By the fall of 2008, the United States had surpassed 20,000 MW of installed wind power capacity, and the country has installed as much wind capacity in the last two years as it did in the previous two decades. Even though wind still supplies less than 2% of U.S. electrical energy, there is a strong sense of optimism and excitement associated with wind turbine technology that has not been seen in the electric power business for quite a while.

Wind turbine technology has evolved rapidly over the last 20 years, allowing for the rapid growth of the industry that we are now witnessing. The North American Electric Reliability Corporation (NERC) has recognized the growing importance of this new source of energy to the power system. In response, it has established the Integrating Variable Generation Task Force (IVGTF) to examine the changes that will be required to the planning and operation of the system, and the associated standards, to accommodate this new source.

Wind plants are different from conventional generation plants in that their fuel supply is neither steady nor controllable, and as a result, they exhibit greater uncertainty and variability in their output. But the current power system also exhibits uncertainty and variability in both the loads and the generation sources, so the difference is in degree only. The current power system was designed and built to deal with variability and uncertainty. Much of what we know about the future impact of high penetrations of wind has been gleaned from wind integration studies performed by utilities and consultants around the world.

EXHIBIT "B"

There is also a growing realization that significahtly increased penetrations of wind power will not be realized without a correspondingly significant increase in the expansion of the electric transmission infrastructure. The current infrastructure is simply inadequate to deliver the large amounts of wind energy available from remote locations to the major load centers, as recognized in NERC's "2008 Long-Term Reliability Assessment" released in October. But now that the problem has been recognized, a number of new approaches and creative solutions are being explored. These include the simple realization that transmission must be included with any new renewable portfolio standard goals in order for them to be realized and the identification of competitive renewable energy zones (CREZ) and their associated transmission corridors. The increased amount of transmission will enable the integrated operation of systems across broader geographical areas, which in turn will enable more efficient operation of broader, deeper, and better-functioning wholesale electricity markets.

To accommodate the uncertainty associated with this new resource, sophisticated wind-plant-output forecasting techniques based on numerical weather prediction models are being implemented. While they are just beginning to be used in North America as the number of wind plants increases, they have been used for more than a decade in Europe. While the United States reached 20,000 MW of wind capacity by the fall of 2008, the remaining world total had exceeded 80,000 MW, most of which was located in Europe. Looking at wind power involves a closer examination of turbine technology, wind plant interconnection and integration, transmission, and forecasting—from both a North American and European perspective. The basis of this examination is the November/December 2007 issue of *IEEE Power & Energy Magazine*, whose theme centered on the application of wind power, a subject that will be updated again in the November/December 2009 issue.

Today's Commercial Wind Technology

Modern wind turbines deployed throughout the world today have three-bladed rotors with diameters of 70–80 m mounted atop 60–80-m towers. The typical turbine installed in the United States in 2008 can produce about 1.5 MW of electrical power. The turbine power output is controlled by pitching the blades. Wind sensors on the nacelle tell the yaw controller where to point the turbine and, when combined with sensors on the generator and drive train, tell the blade pitch controller to regulate the power output and rotor speed and to prevent overloading structural components. A turbine will generally start producing power in winds of about 12 mph and reach maximum power output at about 28–30 mph. The turbine will "feather the blades" (pitch them to stop power production and rotation) at about 50 mph.

The cost of wind-generated electricity has dropped dramatically since 1980, when the first commercial wind farms began operation in California. Figure 1 depicts price data from public records for some more recent wind energy projects. This chart shows that in 2007, the price paid for electricity generated in large wind farms was between 3.5 and 6.5 cents per kWh with an average below 5 cents per kWh (1 cent/kWh = $10/MWh). These figures represent the electricity price as sold by a wind farm owner to the utility. The price includes the benefit of the federal production tax credit, any state incentives, and revenue from the sale of any renewable energy credits.

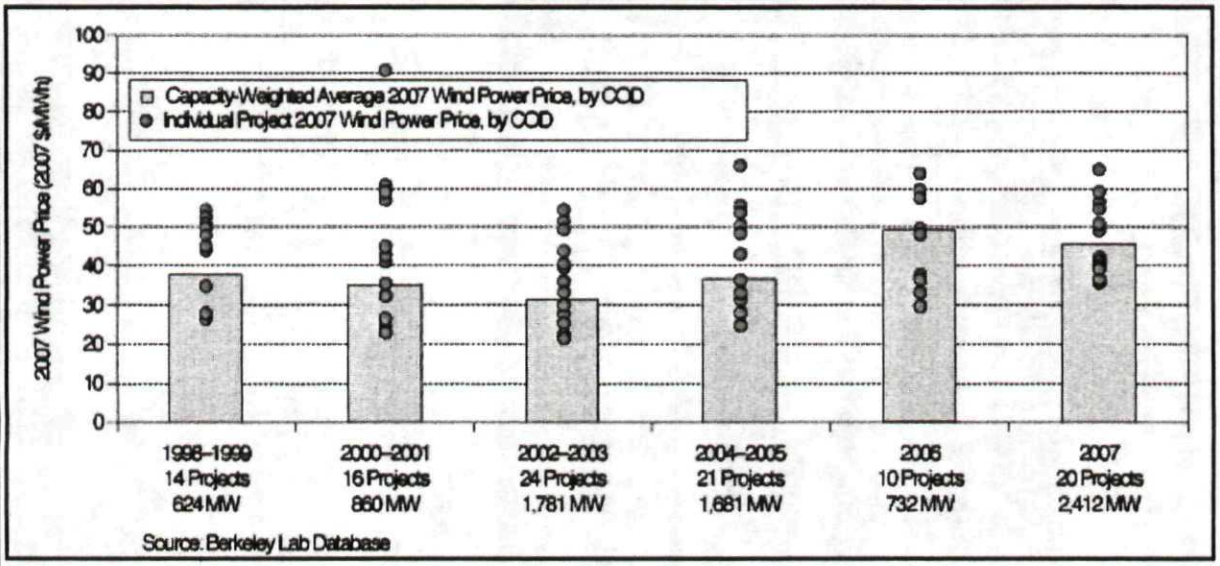

Figure 1. Wind energy price by commercial operation date using 2007 data.

The History of Wind Technology Development

Over the past 20 years, average wind turbine ratings have grown almost linearly (Figure 2), with the majority of machines installed in 2007 rated at 1.5 MW. With each new generation of wind turbines, the size has increased and reductions in the life-cycle cost of energy have been achieved through economies of turbine scale and a larger rotor to increase energy capture.

However, there are constraints to this continued growth in size; at some point, it will cost more to build a larger turbine than the benefit of increased energy increase benefit is worth. In addition, land transport restrictions and cost, as well as crane requirements, can impose size limits for wind turbines installed on land. While there is no "big breakthrough" on the horizon for wind technology, many evolutionary steps executed with technical skill can cumulatively result in a 30–40% improvement in the cost effectiveness of wind technology over the next decades. No major technical breakthroughs in land-based technology are needed for a broad geographic penetration of wind power on the electric grid. Capacity factor can be increased over time using enlarged rotors on taller towers. In addition, with continued research and development, offshore wind energy has the potential to allow the United States to greatly expand the electricity supply to coastal cities at a reasonable cost without long transmission lines.

Getting Connected

In this era of open-access transmission, it is difficult to find an interconnection queue that does not contain at least some wind generation projects; in the areas of the country with good or better than good wind resources, there may be dozens of prospective projects awaiting study. In its "2008 Long-Term Reliability Assessment," NERC estimated that 140 GW of wind capacity could be installed within ten years based on the current interconnection study queues. This situation has brought the electric power engineering community much broader exposure to the technical issues and challenges associated with wind generation.

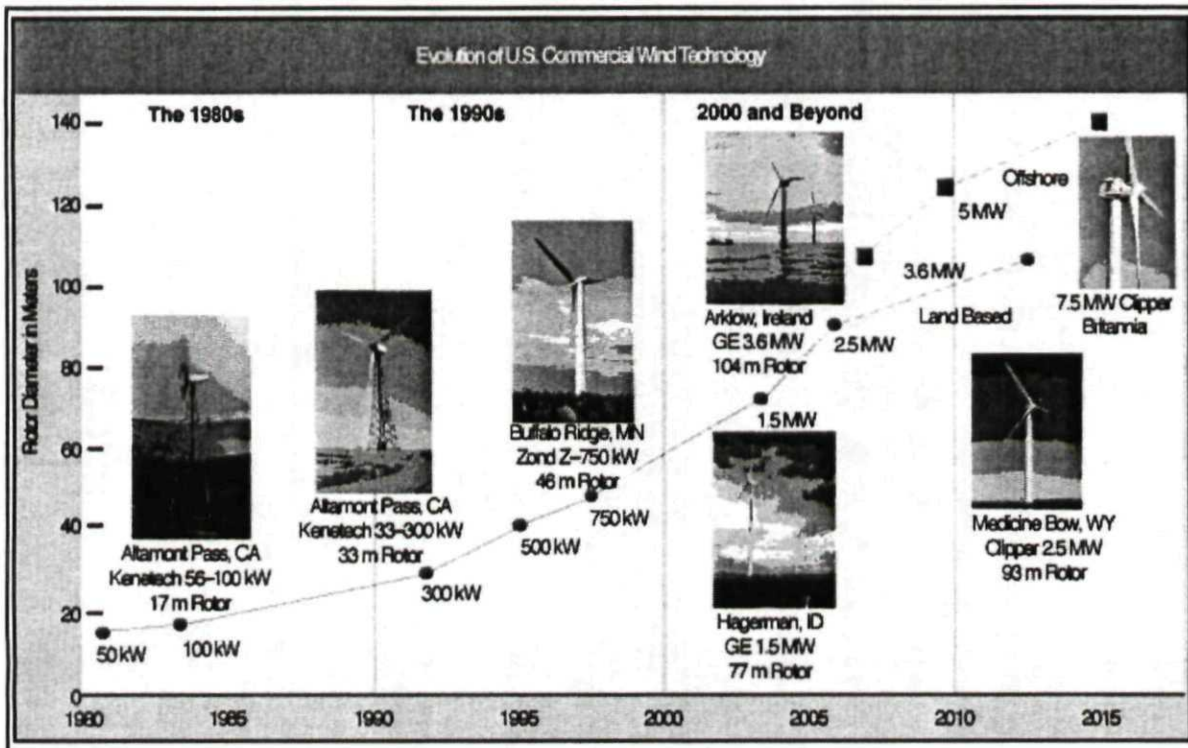

Figure 2. The development path and size growth of wind turbines.

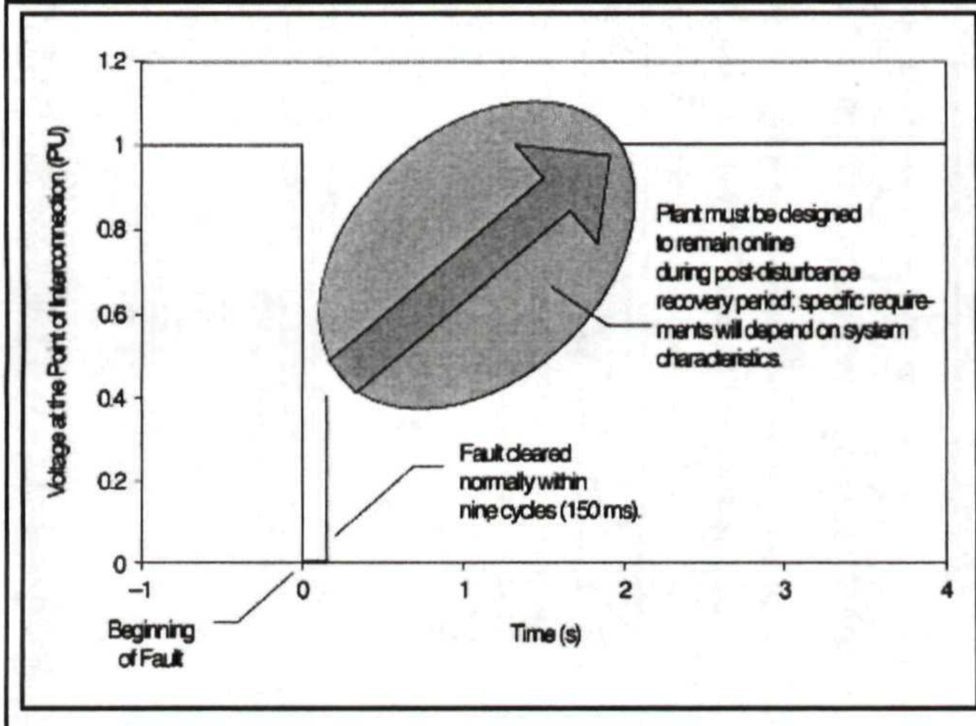

Figure 3. FERC Order 661A requires wind generators to remain connected for voltages as low as zero lasting for up to nine cycles.

At present, FERC Order 661A is the operative standard regarding some aspects of wind plant behavior. The order states that wind generating plants are required to remain in service during three-phase faults with normal clearing (which is a time period of approximately four to nine cycles) and single line-to-ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system (Figure 3). Additionally, the required reactive power range for wind plants is specified, and some relatively nonspecific language about requirements for supervisory control and data acquisition (SCADA) and interoperability with the network is also included.

Simulation models are necessary to conduct interconnection studies for proposed new wind power plants. Models are also required for existing (or committed) wind power plants to conduct periodic assessments of grid reliability and interconnection studies of other proposed projects. Roughly speaking, simulation models fall into two categories: planning models and engineering design models. Planning models are implemented in positive-sequence simulation programs, such as the General Electric (GE) PSLF/PSDS and Siemens-PTI PSSE programs, and they're designed for studies of large-scale interconnected systems, in which simplifying approximations are acceptable and desirable to balance computational complexity, simulation speed, and data management. The utility industry and other users (like consultants, researchers, and students) have grown to expect these models to be nonproprietary, generic, standard, and compatible (or portable) across simulation platforms. Unrestricted sharing of planning models among transmission planners, study consultants, and reliability organizations is needed for generator interconnection studies, as well as grid planning studies. In terms of this need, collaboration with the IEEE Dynamic Performance of Wind Generation Working Group of the IEEE Power Engineering Society (PES) is under way, with the goal of further refining the models and using them as a basis for an eventual IEEE wind turbine generator modeling standard. The work will build on the efforts of the Western Electricity Coordinating Council (WECC) over the past three years to define, develop, and test basic model structures for commercial wind turbine topologies.

Grid requirements for the wind industry are moving toward those applied to other types of generation equipment, such as gas and steam turbines. Through a combination of innovative power system engineering and emerging wind turbine control capabilities, advanced operational features similar to what can be provided by conventional generating plants have been demonstrated. These include:

- **Reactive power supply and voltage control:** Many wind plants are connected to very weak portions of the transmission network. Advanced turbines with closed-loop control through wind plant SCADA can provide for the close regulation of voltage through the management of reactive power within the plant, even under conditions of fluctuating real power production.
- **Real/active power regulation:** Control of active power in response to commands from the grid operator is now possible, although not yet implemented in practice. Such active power controls include power scheduling and ramp-rate limits. As local or regional penetrations of wind increase, such capabilities will provide grid operators with another tool for managing challenging system conditions.
- **Power frequency or governor droop functions:** These can be provided to modify the power reference of the regulator to a configurable droop schedule. Figure 4 illustrates the power response to a 2% increase in system frequency by a 60 MW wind plant with GE turbines. A similar under-frequency response is also possible.

The knowledge base of the electric power system engineering community continues to grow along with the total installed capacity of wind generation in North America. While a similar process has certainly occurred at other times in the industry with other technologies, the relatively explosive growth, the compressed time frames from project conception to commission, and the unconventional characteristics of wind generation make this period of time unique.

The industry is still only part of the way up the learning curve, however. Numerous technical challenges remain, and as has been found, each new wind generation facility has the potential to generate some new questions.

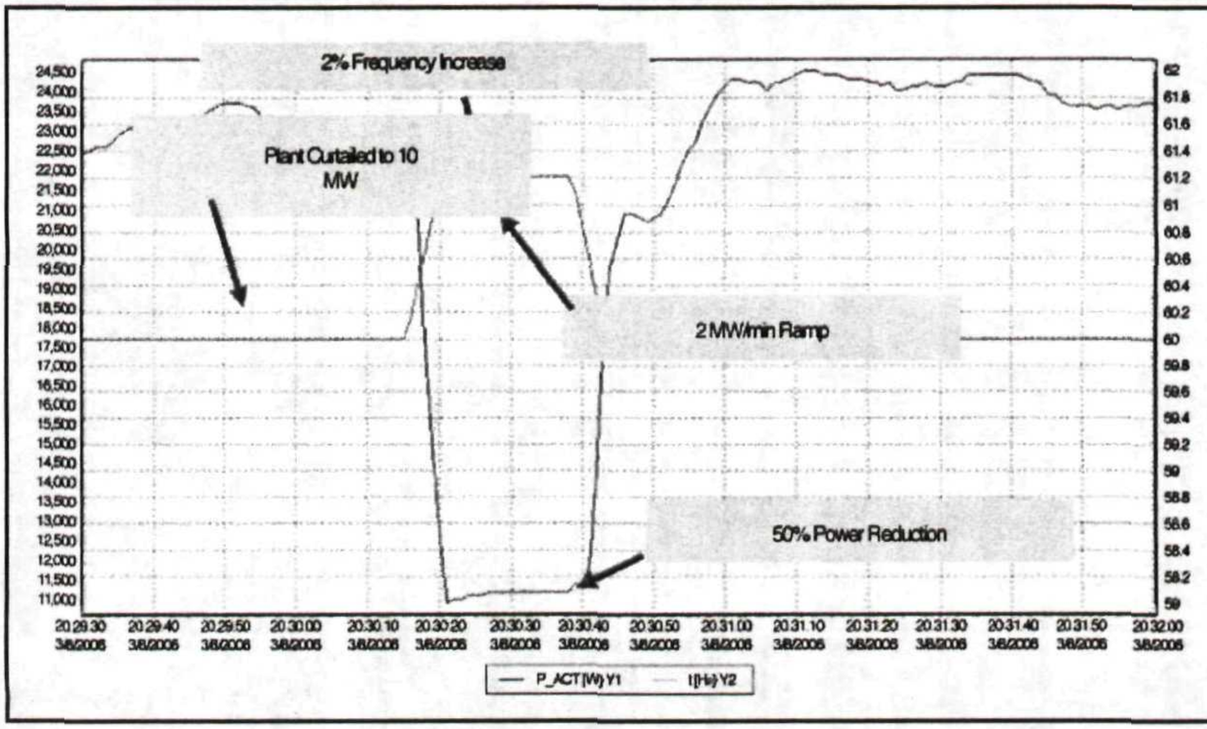

Figure 4. Power response of plant to over-frequency condition.

Integration of Wind Energy into the Electric Power System

Integration of wind power plants into the electric power system presents challenges to power-system planners and operators. Wind plants naturally operate when the wind blows, and their power levels vary with the strength of the wind. Hence, they are not dispatchable in the traditional sense. Wind is primarily an energy resource. Its main value is displacement of fossil fuel combustion in existing generating units. These units maintain system balance and reliability, so no new conventional generation is required as "backup" for wind plants. Wind also provides some effective load-carrying capability (ELCC) and thus contributes to planning reserves but not day-to-day operating reserves. Wind's variability and uncertainty do increase the operating costs of the non-wind portion of the power system, but generally by modest amounts.

The recent studies conducted in the United States use sophisticated atmospheric (meso-scale numerical weather prediction) models to develop credible wind power time series for use in the integration analysis. It is now generally accepted that integration studies should use this type of data, synchronized with load data, if actual wind data are not available. Two new studies of wind energy penetration of 20–30%, use this approach. One covers the U.S. portion of the Eastern Interconnection (the Eastern Wind Integration and Transmission Study), and the other deals with the WECC in general and the WestConnect footprint in particular. These studies, initiated in 2008, are unprecedented in scope and will offer the first detailed examination of a national 20% wind energy scenario. Results from a number of recent integration studies performed in North America were summarized and discussed in the November/December 2005 and November/December 2007 issues of *IEEE Power & Energy Magazine*.

A Minnesota study released in 2006 is a representative example. The 2020 Minnesota system was modeled as the consolidation of four main balancing areas into a single balancing area for control-performance purposes. Simulations investigating 15, 20, and 25% wind energy penetration of the Minnesota balancing area retail load in 2020 were conducted. The 2020 system peak load is estimated at 20,000 MW, and the installed wind capacity is 5,700 MW for the 25% wind energy case. Wind generation data sets were produced from physics-based meso-scale atmospheric models.

Hourly simulations were run for each penetration level and for each of three years of wind data. The cost of wind integration ranged from a low of \$2.11/MWh of wind generation for 15% wind penetration in one year to a high of \$4.41/MWh of wind generation for 25% wind penetration in another year, compared with the same energy delivered in firm, flat blocks on a daily basis. These are total costs and include both the cost of additional operating reserves and costs arising from day-ahead wind-forecast errors. Figure 5 shows these integration costs for the three years studied and the range of energy penetrations considered.

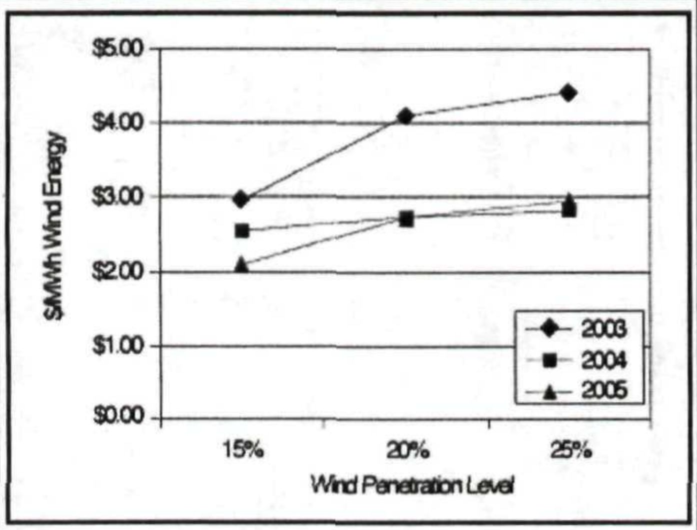

Figure 5. Total integration costs for the 2006 Minnesota integration study.

Of particular note is the fact that these integration costs are below the values obtained in a previous Minnesota-Xcel Energy wind study, reported in a 2005 *IEEE Power & Energy*

The challenge for wind energy transmission can be viewed as a "chicken and egg" situation. Transmission owners have been unable to build new high-voltage transmission lines to remote areas where there may be a high-potential wind energy resource but little existing generation or load. Bottlenecks in high-load corridors typically have priority when it comes to the limited funds available for building new transmission lines. And traditionally, new transmission has been approved only if there is a proven need for system reliability. Wind plant developers, as a result, have not been able to build new wind power plants in remote wind-rich areas unless there is an existing transmission line capable of transferring the plant output to major load centers. So the chicken-and-egg dilemma has obstructed the development of new wind plants and the transmission to deliver the wind energy to consumers. The November/December 2007 issue of *IEEE Power & Energy Magazine* reported on several promising approaches to solve this dilemma. This is an update on progress in Texas, California, and Colorado.

Texas CREZ

Texas developed the concept of CREZ. Under this plan, the Public Utilities Commission of Texas (PUCT) and the grid operator, ERCOT, assessed wind resources throughout the state, selected high-potential CREZ areas for detailed analysis, and developed plans for transmission upgrades to carry generation from these areas to the Dallas/Fort Worth and central Texas load centers. These new transmission projects would not be required to meet the "used and useful" standard, meaning that the transmission companies could start constructing them prior to the development of interconnecting wind resources.

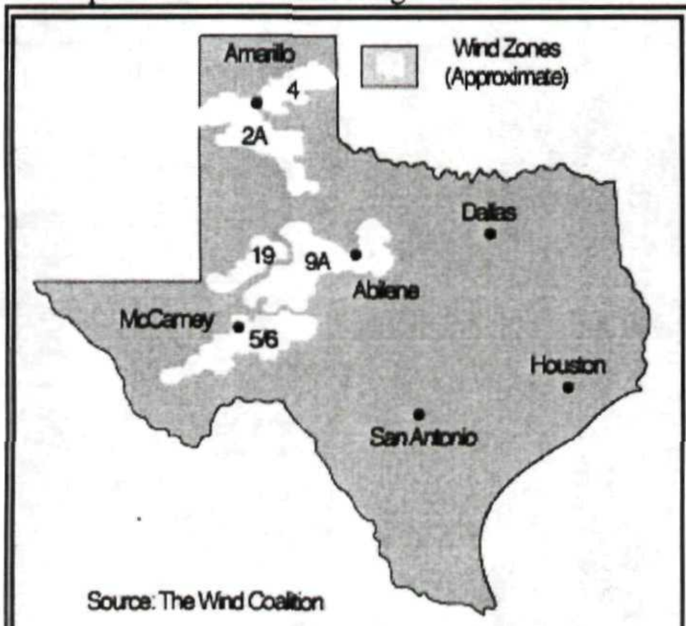

Figure 6. Renewable energy zones in Texas.

Figure 6 shows the renewable energy zones. Table 1 summarizes the four transmission scenarios that were evaluated and indicates the power transfer capability from each zone.

Magazine article on wind integration. That study considered up to 15% capacity penetration in the Xcel-North (NSP) system, corresponding to an energy penetration of about 12%, and found an integration cost of $4.60/MWh of wind generation at this penetration level. This finding clearly shows the benefits of balancing-function consolidation over a wider service territory, access to markets, and diversity of wind resources over a wider geographic area.

Summary of Key Insights on Wind Integration

Wind integration studies conducted over the last several years have contributed important new insights into the impact wind's variability and uncertainty will have on system operation and operating costs.

1. Several investigations of truly high penetrations of wind—up to 25% energy and 35% capacity—have concluded that the power system can handle these high penetrations without compromising system operation.
2. The importance of detailed wind resource modeling has been clearly demonstrated. Meso-scale wind modeling based on multiyear archived weather data and correlated with electrical load data has provided the capability to capture the wind diversification impacts both within individual wind plants and among the various wind plants contained in a balancing area.
3. The value of good wind forecasting has been clearly demonstrated to reduce unit commitment costs in the day-ahead time frame. There is also evidence that faster markets (e.g., 10 min rather than 1 h) can reduce wind integration costs.
4. The importance of increased flexibility in the nonwind portion of the generating mix has been clearly demonstrated. This flexibility could be provided, for example, by some combination of high-ramp-rate fossil generation, hydro units, pumped storage, and demand response.
5. The difficulties of maintaining system balance under light-load conditions with significant wind variability have been illuminated, particularly in recent studies in California and Ontario, Canada. In this situation—usually occurring at night—conventional units have been turned down to the maximum practical extent. Some combination of system flexibility, wind curtailment, wind ramp-rate mitigation, and new loads added in light-load periods will be needed.
6. Although wind is primarily an energy resource, it does provide modest amounts of additional installed capacity for planning-reserve purposes. To date, studies performed in the United States indicate wind capacity values ranging from approximately 8–40% of rated wind capacity—typically in the lower half of this range.
7. The value of sharing balancing functions over large regions with a diversity of loads, generators, and wind resources has been clearly demonstrated. In general, the electric sector is moving in this direction—either through RTO-ISO participation or other means, such as ACE-sharing—because of resulting efficiencies in system operation. Recent studies, particularly those in Minnesota and California, have shown very clearly that this trend will significantly aid in the integration of larger amounts of wind power through reductions in operating cost impacts arising from wind's variability.

Transmission Development for Wind Energy in the United States

In July 2008, the PUCT announced that it had selected scenario 2 and encouraged organizations to work together to help ensure timely, cost-effective development of transmission facilities to support wind power. Scenario 2 envisions the construction of approximately 2,400 mi of new 345-kV transmission lines at a projected cost of $4.9 billion.

The next step is to determine who will build which lines. So far, 16 companies have made 242 offers to build 125 projects, some collaboratively. Additional open issues relate to dispatch priorities and the development of operating guidelines and market rules.

Table 1. Megawatt tiers for ERCOT CREZ transmission optimization study.

	Scenario 1 (MW)	Scenario 2 (MW)	Scenario 3 (MW)	Scenario 4 (MW)
Zone 2A	1,422	3,191	4,960	6,660
Zone 4	1,067	2,393	3,720	0
Zones 5/6	829	1,859	2,890	3,190+
Zone 9A	1,358	3,047	4,735	5,615
Zone 19	474	1,063	1,651	2,051
CREZ transfer capability	5,150	11,553,	17,956	17,516
Total transfer capability	10,000	16,403	22,806	22,366
Source: ERCOT				

California Tehachapi

The Tehachapi region has the potential for more than 5,000 MW of new wind generation, but the opportunity to develop it was stalled because there was no way to fund the necessary expansion of the bulk transmission system. The California independent system operator (CAISO) won FERC approval to create a new transmission category for interconnecting remote, locationally constrained resources, such as renewables. FERC approved CAISO's proposed hybrid financing tool, which has resolved the issue of who will pay for transmission upgrades. Southern California Edison (SCE) received CAISO's approval for the $1.4 billion Tehachapi Transmission Project in 2007. Some transmission segments are now under construction, and a few more are in the proposal stage. This project will deliver more than4 GW of wind generation from the Tehachapi area to the bulk power grid. Completion is targeted for 2013.

Colorado Energy Resource Zones

Colorado is following a path similar to that in Texas. Colorado House Bill 1281 requires 20% renewable energy by 2020 and provides for a renewable-energy credit bonus for in-state generation. The legislature also recognized that state utilities needed tools to expand the transmission grid in advance of the new generation requirements. The Transmission Task Force on Reliable Electricity Infrastructure was established in 2006, and it is charged with mapping energy resource zones (ERZ) and transmission expansion plans. An ERZ is a geographic area in which transmission constraints hinder delivery of electricity, the development of new generation, or both. The task force will submit applications for certificates of public convenience and necessity (CPCN) for specific transmission projects. These applications must be acted upon in 180 days; otherwise, they are deemed approved. Potential transmission projects to serve five ERZs have been identified, and CPCN applications will be filed in early 2009.

Wind Forecasting

Wind power forecasting plays a key role in tackling the challenge of balancing the system supply and demand, given the uncertainty associated with the wind plant output. Wind forecasting is a prerequisite for the integration of a large share of wind power in an electricity system, as it links the weather-dependent production with the scheduled production of conventional power plants and the forecast of the electricity demand, the latter being predictable with reasonable accuracy.

The most important application of wind power forecasting is to reduce the need for balancing energy and reserve power, which are needed to integrate wind power into the balancing of supply and demand in the electricity supply system (i.e., to optimize the power plant scheduling). This leads to lower integration costs for wind power, lower emissions from the power plants used for balancing, and subsequently to a higher value of wind power. A second application is to provide forecasts of wind power feed-in for grid operation and grid security evaluation, as wind farms are often connected to remote areas of the transmission grid. To forecast congestion as well as losses due to high physical flows, the grid operator needs to know the current and future wind power feed-in at each grid connection point.

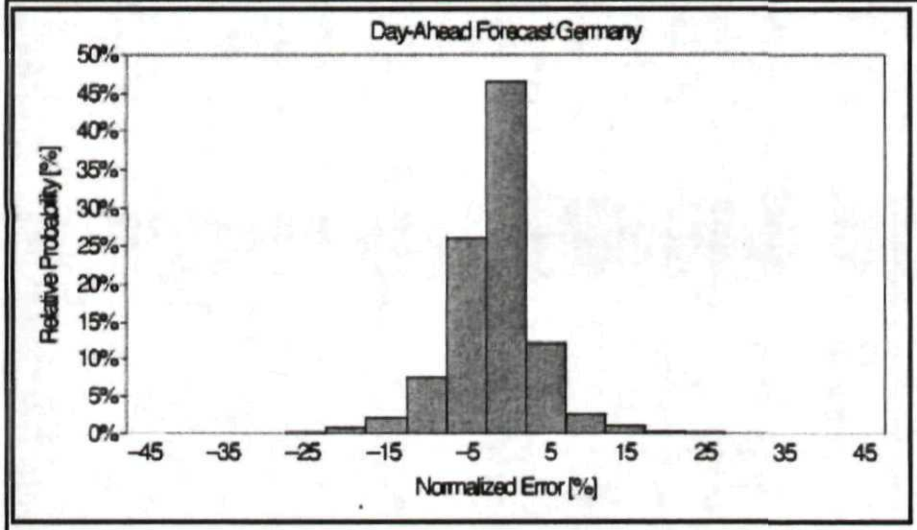

Figure 7. Frequency distribution of the difference between forecast and monitored power output.

Forecast Accuracy

As wind power capacity quickly grows, forecast accuracy becomes increasingly important. This is especially true for large onshore or offshore wind farms, where an accurate forecast is crucial due to the high concentration of capacity in a small area. Encouragingly, in recent years, the forecast accuracy has improved constantly, and it can be expected that this increase can be maintained into the future. The forecast error can be displayed as a frequency distribution. Figure 7 shows an example, using forecast data from a day-ahead forecast performed with ISET's wind power management system (WPMS) using numerical weather prediction (NWP) data from the German weather service (DWD).

Effect of Spatial Spread

If many wind farms are forecast together, the forecast error decreases and the aggregation of large regions with several gigawatt installed capacity will lead to a decrease in the relative forecast error, since there will be cases where the forecast errors of different regions will partly cancel each other out. An example of this is given in Figure 8, which shows the forecast error for the three German control zones with large wind power capacity, E.ON, VET, and RWE, together with the error of the aggregated forecast for an example time series of four days. It can be seen that the forecast error for the aggregated wind power always stays below 2.5%, while the error for single control zones reaches up to 8% of the installed capacity.

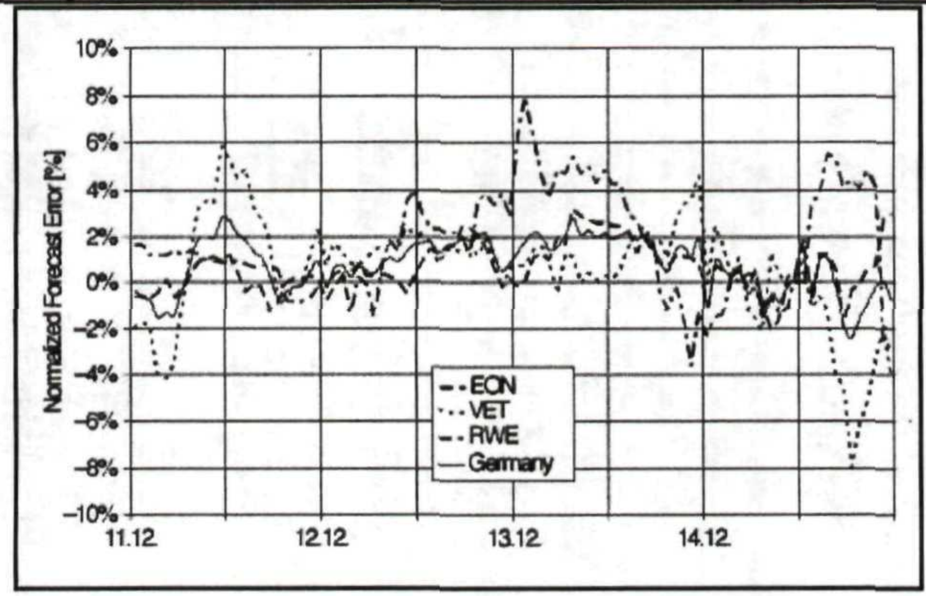

Figure 8. Example time series of relative forecast error for the individual control zones of EON, VET, and RWE, and for the whole of Germany.

Due to increasing wind power penetration, the need for and usage of wind power prediction systems have increased during the last 10 or 15 years. At the same time, much research has been done in this field, which has led to a significant increase in the prediction accuracy. With many ongoing research programs in the field of NWP, as well as in the power output prediction models (transforming wind speed into electrical power output), one can expect further improvements in the future.

Best Practices

For the time being, three measures are taken as best practices to reduce prediction errors.

- **Combination:** Combinations of different models can be done with power output forecast models as well as with NWP models (multimodel and multischeme approaches). Reductions in root mean square error (RMSE) of up to 20% were shown with intelligent combinations.
- **Forecast horizon:** As expected, a shorter forecast horizon leads to lower prediction errors. However, the organization of the electricity market as well as the conventional generation portfolio has a large influence on the forecast horizon required.
- **Spatial spread:** The forecast error depends on the number of wind turbines and wind plants, and their geographical spread. In Germany, typical day-ahead forecast errors for representative wind plant forecasts are 10–15% RMSE of installed power, while the error for the control zones calculated from these representative wind plants is typically 6–7%. The error calculated for the whole of Germany is only 4–5%. Whenever possible, aggregating wind power over a large area should be performed, as it leads to a significant reduction of forecast errors as well as short-term fluctuations.

European Update

When discussing high wind power penetration in power systems, the possible impact of variable wind power production on power system balancing and frequency control is typically of concern. There are two dimensions to the problem: an economical one, related to optimization of the resources and a fair burden sharing of the cost, and a technical one, related to security of supply. As Europe has some of the highest wind penetration levels in the world and high targets to increase the share of wind power, European experience and approaches to balancing and frequency control are of general interest. This includes market-based approaches (i.e., organization of balancing markets) as well as technical solutions, such as using wind plants to provide balancing and frequency services.

The Balancing Issue

Power systems have to deal with uncertainty in both consumption and production. To manage this, reserves are kept in power plants. The reserves are then used for up or down regulation during the operating hour to keep the consumption and production in balance. Up and down regulation are used to keep the total balance in a control or balancing area. As the power system consists of thousands of individual consumers and production units, there is a great benefit in operating the power system so that only the net imbalance needs to be controlled.

Wind energy brings more variability to the power system. Part of this variability can be forecasted some hours or a day ahead. The uncertain part of the variability is left for reserves in the power system. During the operating hour, the imbalance of wind is added to all other imbalances in the power system—wind power does not need dedicated backup.

In many European countries, wind power imbalances are treated in balance settlement after the operating hour, like all other production and consumption. Through the imbalance costs, wind power producers will see the cost that has been incurred through the increased use of reserves (except in those countries where the transmission system operator (TSO) covers the imbalance costs, such as Germany and Denmark). However, in most countries, the technical costs that have actually been incurred are not directly allocated to the market participants; rather, penalties are imposed. This means that in some countries, wind power producers are paying more for imbalance costs than the actual cost increases. As wind energy penetration increases, it will be asked to act as a balancing source, like other generators. We need only the correct market mechanism to send the needed economical signals, since, from a technical point of view, the response of the wind energy generation is very fast.

Horns Rev Offshore Wind Farm: Providing Balancing and Frequency Support

For the majority of wind turbines developed in the last century, the automatic control of wind power installations was implemented in the individual wind turbines, and the main aim of the wind turbine controllers was to ensure maximum production, minimum mechanical stress, and meet noise emission limits.

In this century, the wind turbine and wind farm control systems have been equipped with several new features supporting the grid integration of the wind plant. Individual wind turbine controllers now have fault ride-through control capabilities that enable the wind turbines to stay connected during and after grid faults in the power transmission system. New features also have been added to wind turbine controllers for normal conditions. The wind turbines have active and reactive power set points available for external control. Wind plant controllers use these set points to support the power balancing and frequency control functions in the power system. The most significant step in this development so far is the wind plant controller for the Danish plant Horns Rev, the first large offshore wind plant. The Horns Rev wind plant consists of 80 Vestas V80 (2 MW) wind turbines with the doubly fed asynchronous generator (DFAG) technology.

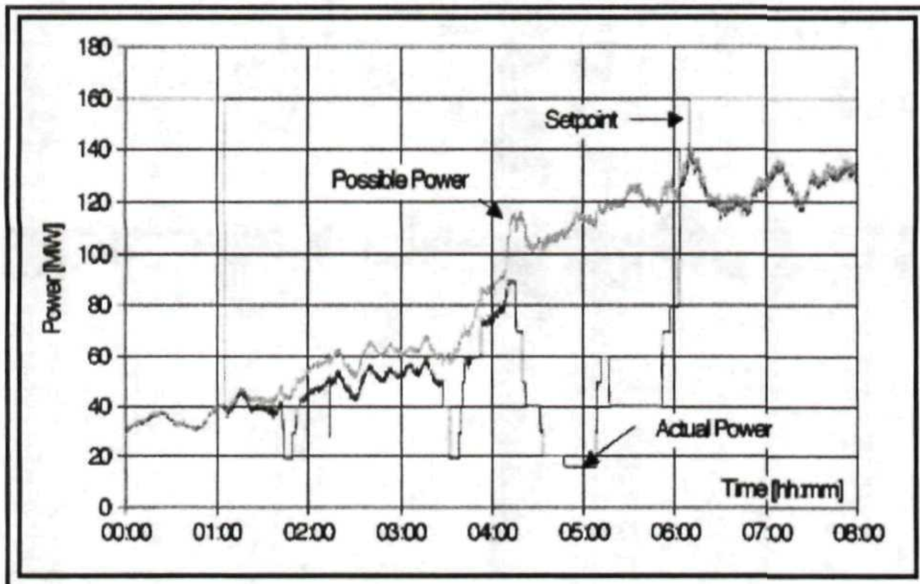

Figure 9. Example of a "normal" day of operation of the Danish Horns Rev wind plant.

An example of a "normal" day of operation of the Horns Rev wind plant is illustrated in Figure 9. At about 1:10 a.m., the frequency control is activated to provide a spinning reserve that can be used in case of underfrequency. This causes the actual power generation of the wind plant to decrease below the theoretically possible power production. At about 1:40 a.m., a manual balance order is issued, causing the power to be reduced to 20 MW. After a few minutes, a new order is sent, and shortly after that, the balance control is cancelled again. The frequency control still keeps about 10 MW in reserve for the next few hours. The dip of power at about 2:10 a.m. is actually caused by the frequency control reducing the power because a fast frequency rise occurred at that time. At about 3:30 a.m., a new set of balance orders is issued. From about 4:00 a.m. to 6:00 a.m., the power is reduced significantly because of overproduction in the grid. Then, the balance control and frequency control are cancelled, and the wind farm returns to normal operation.

The experience with the Horns Rev offshore wind plant demonstrates that the power and frequency control functions provided by a wind plant are very useful tools to support the daily operation and control of the Danish power system. The Horns Rev wind plant main controller has operated as an integrated part of the central system control ensuring the power balance in the system. It is expected that such functionality will be inevitable in future power systems with large-scale wind penetration. For instance, in the present Danish system, wind power produces almost 20% of the electricity, but according to government plans, this number will increase to 50% by 2025.

Conclusion

Developments in the world of wind continue to happen at record speed. The world as a whole is in the midst of grappling with an epochal transition from a system dominated by fossil and nuclear fuel to one that relies much more heavily on renewable energy. No technology breakthroughs are required for the United States to achieve the scenario of 20% of electricity from wind by 2030. Instead, many evolutionary steps executed with technical skill, which can cumulatively result in a 30–40% improvement in the cost effectiveness of wind technology over the next few decades, are expected to occur.

The IEEE PES is expanding its presence and activities in this increasingly significant commercial arena, and the prospects for building and operating a robust power system that can manage the variability and uncertainty associated with the 20% wind scenario are looking increasingly bright. Wind forecasting is playing an increasingly critical role in the operation of power systems with a high share of wind generation. The stalemate in transmission development is coming to an end, with a new transmission planning paradigm being implemented. Several major projects have been initiated, and progress is accelerating across the country.

The Europeans are leading the way with increasingly sophisticated wind power plant operational capabilities, demonstrating the ability of a wind power plant to provide spinning reserves and frequency responsive governor action. And the small country of Denmark has embarked upon an ambitious course toward providing 50% of its total primary energy needs from renewables, primarily wind power, by 2025. In 2030, it will be interesting to look back and judge the ambition of the goals we are setting for ourselves now.

Acknowledgments

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Response to NPRI Paper on Feed-in Tariffs in Docket No. 2008-0273
By Mohamed M. El-Gasseir, Ph.D. on behalf of Tawhiri Power LLC

Tawhiri Power LLC ("TPL") commends the Public Utilities Commission of Hawaii ("Commission") for sponsoring the scoping paper prepared by its consultant the National Regulatory Research Institute ("NRRI") on feed-in tariff ("FiT") design issues. The paper provides an excellent starting point for identifying and discussing the proper conditions and requirements for designing and implementing an efficient and equitable FiT for Hawaii. However, perhaps due to lack of time and the very sparse experience with FiT development and practices in the U.S., the NRRI paper has a number of limitations including:

- Key FiT threshold design and implementation issues have not been addressed;
- Insufficient attention to some of the identified issues as the paper was focused on one particular form of FiTs, namely the Project-Based FiT ("PBFiT");
- A tacit endorsement of an inadequate FiT implementation schedule advocated by the HECO Companies and the Consumer Advocate ("Sponsoring Parties"); and
- An impracticable approach to soliciting information from potential developers.

1. Summary of TPL's Principal Recommendations

As discussed in the ensuing sections of this submittal, TPL recommends the following:

1. Allow more time to conduct a thorough and open evaluation of the potential direct and indirect impacts on ratepayers of implementing PBFiTs at a scale and pace greater than pilot projects. (Direct impacts will be caused by the need to subsidize new FiT contracts. The indirect ones will reflect the costs of potential stranded assets and curtailment of renewable generation priced at unsubsidized avoided utility costs.)
2. If allowing more time for FiT development and implementation is not possible, the Commission should limit PBFiTs to pilot-scale programs for the promising options.
3. If the Commission must immediately venture beyond pilot-scale PBFiTs, then it should adopt a total (all technologies) cap for each HECO Company equal to each utility's projected increase in electricity demand over the ensuing 12 months.
4. Irrespective of the adopted scale of development or cap levels, the Commission should institute a policy of ***do-no-harm*** to prevent curtailment of renewable energy production from existing avoided-cost priced resources and to compensate the owners of such resources in cases where curtailment cannot be circumvented.
5. To eliminate conflict of interest, affiliates of the HECO Companies should be barred from doing business through PBFiTs.
6. To maximize participation by developers and to enhance the accuracy and value of their data responses, the Commission should solicit the technical and cost information it needs for designing sound and fair PBFiTs through a blind process administered by a neutral, competent agent (e.g., a reputable accounting firm). The Commission's protective order is not likely to induce prospective developers to provide accurate and meaningful confidential information for useful application in the FiT proceeding.

EXHIBIT "C"

2. Missing Threshold Issues

In our opinion, a threshold issue is one whose outcome could significantly impact further development of a FiT program in Hawaii or even hinder it completely. The subject paper has correctly identified two categories of such issues. One category involves "legal" questions pertaining primarily to potential conflicts with the Public Utilities Regulatory Policies Act ("PURPA"). The second pertains to policies regarding "other incentives" for encouraging renewable energy development.

There are four more issues that deserve immediate focus as threshold questions since the outcome of their consideration is bound to significantly determine the objectives, design and timing of a Hawaiian FiT program. They are:

1. Should Hawaii's PBFiT program be part of a wider and balanced strategy to minimize the production of greenhouse gases (GHG) and dependence on imported fuels at least cost to the public and to Hawaii's economy?
2. Is it proper to allow HECO Companies' affiliates to sell power to HECO under a PBFiT program?
3. Should PBFiTs be confined to generation interconnected at distribution voltage levels?
4. Can the Commission proceed with a pilot-scale PBFiT program before engaging in a wider experiment with little information to rely on?

In fairness to the NRRI, the scope of the paper was apparently limited by design.[1] It should also be noted that the first two topics were considered albeit indirectly and not as threshold issues.

We urge the Commission to seriously consider the aforementioned additional questions for the following reasons:

- One cannot pursue the minimization of GHG production and of dependence on imported fuels without seeking to achieve these concomitant goals at least cost to consumers. This means designing a PBFiT program that is part of a carefully balanced portfolio of power acquisition options which collectively can reasonably assure ratepayers of a minimally painful transition to new resources and technologies. Such portfolio would consist of existing and future bulk-power purchases at negotiated or bid prices, avoided cost based contracts, and future PBFiT supplies. Continued reliance on a balanced basket of preferred-resource options is essential considering the proposed FiT regime is a regulatory mechanism to encourage renewable energy development by guaranteeing prices at cost-plus rates. Ensuring the integrity of existing and future contracts which do not cost ratepayers more than what they would be otherwise paying the HECO Companies is an important means of protecting the public against unintended consequences of a hurriedly conceived PBFiTs.
- Allowing a utility affiliate to engage in supplying power to its customers invites nasty and intractable conflict-of-interest issues.[2] To believe otherwise is to ignore the elephant

[1] On Page 2, the author states, "Per our assignment, this paper focuses on only on feed-in tariffs and makes no assessment about the relative merits of these various approaches."

[2] Consider, for example, the fact that the utility would be both the load forecaster and the buyer of PBFiT generation from its own affiliate (on behalf of ratepayers).

in the room. There are three PBFiT-participation models to choose from: (i) Ban utility affiliates from selling energy to HECO Company customers under FiT contracts; (ii) Allow them to compete for such opportunities with independent developers; and (iii) Ban independent developers. Option (i) offers the only way to eliminating conflict-of-interest problems. The second approach will maximize the incidence of conflict of interest and the need for micromanagement of the market by the Commission. In addition to the prospect of legal challenges, limiting participation in PBFiTs to utility affiliates will deprive Hawaii's consumers and economy from the benefits of competition in a green technologies industry that is inherently market driven.

- Questions regarding the scope of the PBFiTs in terms of location and size were repeatedly posed in the paper, but the issue of whether to limit the new tariffs to distribution-level applications was not raised. Non-utility resources interconnected at the transmission level already play a pivotal role in making Hawaii the leading state in terms of renewables' share of electric power generation. The majority of these resources supply power at avoided utility costs; a form of FiTs that ensures consumers would not pay more than they would have paid their power company for the energy purchased on their behalf. That is to say renewable energy is being procured without the need to pay premiums. In contrast, the amount of renewable capacity interconnected at the distribution level is comparatively severely lagging. The opportunities for PBFiT are at the low end of the voltage spectrum. Developing and implementing PBFiTs requires a complex process and one that necessitates adequate time and resources. The prudent strategy is to narrow the scope of the investigation and associated Commission efforts to distribution applications.
- Time imitations, multiplicity of issues, and lack of relevant experience with PBFiTs point to the need for a more cautious approach to fulfilling Hawaii's FiT goals. TPL recommends that the Commission start with a pilot PBFiT program at the distribution level of each HECO operating company that can be effectively improved and expanded with time.

3. Issues Warranting More Attention

Several issues identified in the paper deserve special attention:

- The author recommends the Commission "should require that the signatories to the Agreement [,] and encourage all [other] parties [,] to explain how these other incentives will interact with a PBFiT and what a PBFiT will do that the other incentives will not accomplish".[3] While we concur with this requirement it is not realistic to expect that any party can adequately meet it in the extremely tight schedule governing the FiT proceeding. Accordingly, we urge the Commission to issue a *do-no-harm* companion ruling or directive to assure that no adoption of any PBFiT would end up negatively impacting existing power contracts between HECO Companies and independent power producers (IPPs) and owners of Qualifying Facilities (QFs).
- The paper also recommends the Commission require that the parties "suggest modifications to the current incentive mechanism that may be able to encourage the

[3] NRRI Paper, Page 4.

development of renewable resources in similar amount as a PBFiT."[4] The author then suggests example enhancements of current mechanisms including "establishing predictable long-term avoided costs that are the basis for payments for an extended period".[5] We appreciate the fact that an organization as reputable as the NRRI is calling for attention to the need to not overlook the avoided cost mechanism that has enabled Hawaii to be at the forefront of encouraging high contribution by renewable energy resources to meeting electricity demand without spending one dollar on incentives to producers. (The avoided cost mechanism ensures that ratepayers are price-wise indifferent as to the source of electricity.) While we whole-heartedly agree for the need to encourage QF development, TPL strongly recommends investigation of two additional and very relevant issues:

- The risk to current intermittent renewable energy investments of facing increasing technical and/or economic curtailments as a result of growing infusion of new intermittent and must-take resources acquired through new bilateral contracts and PBFiTs. Does it make sense to buy future renewable energy at premium prices while curtailing renewable resources secured at prices guaranteed not to exceed utility costs of production? The practice of unilateral and inexplicable curtailment is not a phantom concern. It is already here. Production from TPL's wind energy farm at Pakini Nui was curtailed significantly by Hawaii Electric Light Company ("HELCO") in 2007 and 2008. Cutting production from as-available renewable resources priced at the utility's avoided cost to make room for higher priced generation contravenes ratepayers' interest and public policy objectives. The Commission should be very vigilant about avoiding PBFiT designs that could lead to undermining the goal of expanding renewable energy contributions at least cost to the citizens of Hawaii.
- Based on our experience with Docket 7310, the Commission can and should improve upon due process and transparency practices in its proceedings. In particular, instituting PBFiTs as part of a fairly and efficiently balanced portfolio of renewables that does not undermine existing contracts will be seriously jeopardized if the due process is deficient and/or transparency is lacking as has been the case in Docket 7310. We cannot have significant decisions decided by a subset of parties in isolation from the majority, and it is blatantly unfair for the utility to rely on a black box model inaccessible to renewable energy generators such as TPL.

- The paper raises several unanswered questions concerning the types of PBFiTs to be developed and the desirability of setting a cap on the electric power to be acquired through them. We make three observations here:
  - TPL believes that these issues can be resolved only through quantifying the impacts on ratepayers of different levels of PBFiTs implementation and success scenarios <u>while accounting for</u> changes in avoided cost projections and the likelihood of imposing technical and/or economic curtailments on existing renewable energy generators.

[4] Ibid, Page 4.
[5] Ibid, Page 4

- o The PBFiT proponents' objective to provide financial incentives to disseminate high-cost renewable energy technologies is understandable but they should not lose sight of the need to avoid reducing the contributions of existing intermittent resources or degrading their property values. If developing PBFiT technologies is a must and curtailing current renewables production is unavoidable, then mitigation measures are warranted, including imposing caps on contracted PBFiT capacities and compensating owners of pre-existing renewable resources for incurred losses. There is no basis or need for discriminating between investments in green technologies.
- o If the Commission wants to stay the course with respect to the Government-HECO sponsored target date for implementing PBFiTs, it is not likely that this proceeding will produce meaningful and timely quantification of the impacts of PBFiT designs on ratepayers. In this case, we recommend that the Commission adopt a total cap covering all applications and fair management of project approval queue as described in Attachment A of this submittal.

- The NRRI paper suggests that the Commission may wish to consider focusing on "PBFiTs that merit priority attention based on the projects under consideration, or that might be more likely candidates for consideration based upon the existence of a reasonable PBFiT".[6] While it is not clear what the phrase "projects under consideration" means, we concur with this suggestion as long as the *do-no-harm* principle is observed. We also recommend (as previously stated in this response) that the Commission should start with a pilot program. NRRI bases its suggestion to limit the scope of its initial efforts on the difficulty of managing numerous PBFiTs to cover the many types of technologies involved and location-dependent variations in development costs, productivity, etc. This is true. We also add that controlling the costs of the required subsidies while ensuring equitable treatment of all applicants necessitates micromanagement and administrative details beyond anything that this Commission, or for that matter any commission in the U.S., has ever experienced.[7] This daunting task may explain the <u>glaring fact</u> that hardly two states have ventured into FiT programs.[8] It should be noted that irrespective of how detailed the contemplated PBFiT is, it cannot be administered by the HECO Companies or any affiliates especially if such affiliates were to be allowed to participate in the new markets.

4. PBFIT Development Schedule

TPL supports the establishment of feed-in tariffs for promoting renewable energy growth in Hawaii. But instituting PBFiTs to increase renewables' share of electricity generation at a high pace of development represents a monumental paradigm shift that <u>cannot</u> be rushed through the

[6] Ibid, Page 6.

[7] The NRRI paper implies that "typical" or prototype projects can be found for each technology and each island. Such simplification may not be possible in view of the substantial intra-island topographical, climatic and land-value variations. (Consider for example the variations across Maui and Big Island.) Fairness and economic efficiency will require several PBFiTs for each technology and each island.

[8] Actually, the California Public Utilities Commission (CPUC) made an attempt in the late 1980s and early 1990s to establish a location-dependent feed-in tariff for IPPs and QFs. The CPUC's frustration from the failed effort is probably the primary reason for its rush into a market restructuring that led to the 2000/2001 meltdown that caused California losses exceeding $40 billion.

proposed schedule, including the response times suggested in the NRRI paper. Developing sound and efficient <u>least-cost</u> PBFiTs should not be dictated by minority decisions or the latest headlines. *The ratebases of the Islands' systems – especially on the Big Island and Maui* – are too small to subject them to experimental and hurriedly conceived subsidization programs fashioned after European models. Ignoring Hawaii's unique market circumstances and consumers' vulnerabilities could lead to unacceptable cost shifts between rate classes, stranded assets, costly disruption of service from existing QFs, sharp escalation of retail rates and even heightened risk of death spirals for the HECO Companies.

If the Commission intends to adopt a schedule designed to meet the FiT implementation deadline targeted by the Agreement between the State Government and the HECO Companies, we then recommend that the Commission start with a pilot-scale development of PBFiTs and that the total allowable subscription to the new tariffs be limited to the projected increase in electricity demand for each utility over the ensuing 12 months. We also urge the Commission to adopt the principle of *do-no-harm* to protect existing renewable energy investments that have been serving Hawaii without the burden of subsidizations (as discussed earlier in this document).

5. Project Information Solicitation

The availability of accurate and detailed costing and technical data about candidate renewable energy technologies is essential to designing equitable and efficient PBFiTs. However, obtaining such information from competing developers as envisioned in the NRRI paper in sufficient amounts is practically improbable. It is in the interest of every developer to see that the Commission adopts tariffs that could enable it to secure the necessary financing and an adequate profit margin. But no developer is anxious to reveal its actual expectations about crucial information such as the cost of land, project size, etc. Developers' concerns over releasing sensitive business data are not likely to be adequately addressed by a protective order. TPL proposes that the Commission adopt a blind information solicitation process that can assure the anonymity of the sources of the gathered data. We will be happy to provide details on how to accomplish this at the Commission's request.

Attachment A

PBFiT Project Enrollment Management

The NRRI paper poses a number of important queue management issues. TPL proposes the following principles for managing project enrollment in a PBFiT program:[9]

- Capping PBFiT enrollment on a total basis for all technologies:
  - The Commission should set an initial total cap for each utility equal to next year's forecasted increase in electricity demand plus an adequate reserve margin adder if needed;[10]
  - The total cap should be updated downward to account for projects entering the queue and upwards for projects exiting it; and
  - The total cap should be updated once a year by accounting for subsequent years' demand growth;
- Entering the queue:
  - Entry into the queue is possible as long as the cap has not been reached;
  - To enter a queue, the interested developer must demonstrate that it secured all needed permits to install and operate the targeted generating facility; and
  - Every applicant seeking to enter the queue must pay a queue management fee and a reservation deposit to be refunded when its project successfully exits the queue by coming on line before the expiry of its residency in the queue;
- Residency in the queue:
  - A developing (applicant) project cannot stay in the queue past a Technology-Specific Maximum Allowable Residency Period (TSMARP); and
  - The Commission should determine the TSMARPs on the basis of industry surveys of construction and installation times;
- Exiting the queue:
  - An unfinished project can voluntarily exit its queue before the expiration of its TSMARP but will have to forfeit its queue reservation deposit;[11]
  - A project is deemed to have exited the queue with forfeiture of the reservation deposit upon failing to come on line before its TSMARP has expired; and
  - A developing project that comes on line before the expiration of its residency will be considered to have successfully exited the queue and will be refunded the reservation deposit.

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[9] Although, for the sake of brevity, the case of having multiple (parallel) queues for managing separate enrollments by different renewable generation technologies will not be discussed here, the outlined principles are essentially the same.

[10] If a pilot project approach is used, the initial cap can be less than the projected load growth.

[11] The risk of forfeiture should be high enough to bar phantom projects and prevent gaming.

<u>Proposed Solution for the Curtailment Issue</u>

Prepared on Behalf of Tawhiri Power, LLC

By Mohamed M. El-Gasseir, Ph.D.

For the

Feed-in Tariff Proceeding

March 30, 2009

EXHIBIT "D"

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Proposed Solution for the Curtailment Issue As It Relates to the Unintended Consequences of Project-Based Feed-In Tariffs

Mohamed M. El-Gasseir, Ph.D.

March 30, 2009

A utility may curtail renewable energy deliveries (and hence production) when its generation and/or transmission systems are not sufficiently flexible to accommodate all of the energy produced. The practice of curtailing generators is already a common occurrence in Hawaii, and the losses for independent power producers (IPPs) and ratepayers have been substantial. Without an effective solution to this problem the situation will worsen significantly given the relatively small size of Hawaii's electric power systems, the abundance of renewable resources in the islands, and the intent of policymakers to encourage significant growth of renewable generation through several mechanisms such as establishing a Feed-in Tariff (FiT). Current proposals to deal with the curtailment issue emanate from a perspective that views renewable resources as the *disruptors that must be penalized for intruding on the operation of oil-fired generators.* This paper addresses the issue by taking a viewpoint more in line with a public policy that aims at transitioning Hawaii to an economy and a civilization fueled entirely by renewable energy resources. The perspective use views renewables as the resources to be accommodated and the current infrastructure as the system that must be restructured as soon as possible. More specifically, the paper:

1. Highlights the consequences of continuing to force generators to cut down production without adequate compensation for revenue erosion; and
2. Proposes a solution to the problem that effectively deals with the causes and the consequences of curtailing power deliveries.

1. The Consequences of Curtailing Renewable Energy Production

This practice, which is bound to increase if the growth of the renewables sector is not accompanied with adequate investment in the betterment of the HECO systems, will result in a number of unintended negative consequences, including:

- Assured revenue-erosion for renewable energy developers;
- Project failures;
- Inefficient Feed-in-Tariff (FiT) pricing;
- Discrimination among renewable generators and between renewables and fossil-fired facilities;
- Cumbersome processes for prioritizing and enforcing curtailment;

- Slowing down of the shift from fossil-fired generation; and
- Suppressing system betterment to facilitate absorbing more renewable.

1.1 Revenue Erosion

Under the HECO-proposed FiT schedule, generators will not be paid for curtailed energy. The consequent risk of revenue erosion will be marked by:

- A rising trend for any individual renewable energy generator; and
- Expanding domain.

The increasing risk trend will be an inescapable conclusion if generators are subjected to curtailment without compensation and the State of Hawaii continued to pursue even moderate development of renewable resources through FiT and other mechanisms without aggressive investment in system upgrades. Moreover, because of uncertainties inherent in the timing and impacts of utility infrastructure investments, the risk of future mitigation of revenue erosion will not be easily predictable for project financing purposes. This result will increase the cost of capital for renewable energy developers.

Because a utility cannot and should not discriminate among independent power producers (IPPs), an increasing trend in the need to curtail IPP energy deliveries to the system is bound to expand the domain of revenue erosion to include firm energy resources in addition to intermittent (variable) generators. In a system where seniority rules have to be enforced to protect pre-existing investments, geothermal and biomass fueled facilities may very well be curtailed in advance of variable resources. Even curtailable solar-powered generators may not escape revenue erosion when IPP, distributed resources, self-generation and non-curtailable FiT energy reach high penetration levels.

1.2 Project Failures

With revenue erosion there will be the risk of project failures. Some of this might take place early on as developers fail to secure affordable financing for proposed investments. In other cases a facility might be forced to close down if the reduction in revenues due to curtailment forces the owner into financial default.

1.3 Inefficient FiT Pricing

The prospect of revenue erosion will force developers to demand higher contract prices. If the Public Utilities Commission (PUC) ignores such demands, revenue erosion will continue and may even intensify, leading to the consequences discussed earlier. PUC approval of increased FiT prices could easily lead to overly determined prices or severely understated values. Either way, the adopted prices are likely to be inefficient since they will not diminish the incidence of curtailment.

1.4 Discrimination Among Generators

Lack of communication and control systems (due to cost and other factor) may prevent curtailment of generation interconnected at the distribution level or delivered on the customer side of the meter. Such facilities would continue operating in spite of their contributions to the need to curtail production and delivery of IPP generation because of system inflexibilities. This in turn means disproportional curtailment of renewable energy deliveries at the subtransmission and transmission levels. The resultant discrimination can be the basis for legal challenges that could slow down or even end FiT development efforts in Hawaii.

Curtailing IPP generation without fair compensation could also lead to another form of discrimination: one between the HECO operating companies and the generators delivering energy to consumers through the transmission and distribution systems of Oahu, Maui and the Big Island. The HECO utilities are currently seeking PUC approval of decoupling their revenue requirements from retail sales. If successful, this change in the ratemaking process will enable each operating company to recover its target revenue requirements irrespective of the amount of generation actually delivered to its customers. An IPP can achieve similar protection against revenue erosion if it were assured of a steady level of earnings regardless of the level of curtailment it had to endure. Guaranteeing revenue recovery for the utilities while exposing renewable energy developers to curtailed deliveries is clearly as blatant a form of discrimination as can be.

1.5 Problems with Seniority Rules

Until the HECO companies implement the upgrades needed to minimize the inflexibilities of their generating and transmission systems that prevent unhindered accommodation of renewable generation, the magnitude and frequency of curtailed energy deliveries will continue to increase as more generation comes on line and/or more loads are lost to self-generation, conservation and load management. Thus, with every entry by a new generating facility, existing IPPs will face increased risk of revenue erosion. Without monetary compensation in one form or another, the only method that can be used to minimize the unintended harm is the enforcement of a preferential treatment in the allocation the needed level of energy delivery curtailment on the basis of temporal seniority. In other words, the newer facilities would have to be curtailed first and oldest ones curtailed last. Pre-existing investments have a rightful expectation of do-no-harm. Moreover, no one should expect an already committed investor to shoulder the revenue erosion of future developers.

Although it is unquestionably necessary in the absence of adequate compensation for lost IPP revenues, allocating curtailment by seniority is no easy task, often contestable and can be inefficient. Determining which project is more senior requires developing and implementing rules and procedures in a totally transparent manner. (It should be noted here that from TPL's perspective HELCO's management of the curtailment queue in the Big Island has so far been very discouraging.) As the IPP/FiT sector expands, the burden of processing seniority schedules and adjudicating complaints and counter-complaints could grow to unmanageable levels for the utilities, the PUC and the IPP community; adding significantly to the transactions cost of Hawaii's transition to a renewables electricity economy.

The question of efficiency extends beyond process and adjudication costs. If the PUC were to settle on minimizing harm to pre-existing investments by applying seniority rules rather than compensating generators for curtailed energy, the utilities will not be able to determine who to curtail on purely system reliability and security grounds. When generators are assured of full compensation for lost revenues, they should be indifferent to how much and how often they could be curtailed. Seniority becomes irrelevant. The operating company will have free reign in determining the most effective (technically and cost wise) curtailment plan, including identifying the set of generators whose energy deliveries should be reduced. Such operational planning flexibility is good for maintaining system reliability and grid security within acceptable performance criteria. It also improves the long-term planning process as the HECO companies start to move seriously in the direction of upgrading their generation and transmission systems to maximize the ability of their grids to absorb renewable generation.

1.6 Slowing Down of the Shift from Fossil-Fired Generation

Business-as-usual curtailment will slow down the transition away from fossil fuels in two ways. First, there is the fact that any time a HECO utility decides to reduce deliveries from a renewable resource it means the substitute has to be oil-fired generation. There is nothing in the business-as-usual approach that could change this practice. Relying on seniority rules to lessen the pain will only prolong a bad approach that should not be used; namely, curtailing renewable generation without compensation. Second, system dynamics and substantial declines in oil prices could in fact increase the magnitude and frequency of the curtailment of renewable generation above and beyond what one would expect from the addition of a known amount of variable (intermittent) generation. This phenomenon appears to be supported by recent experience (since 2007) on the Big Island, where there is evidence of a growing retreat from wind power to make room for more generation from HELCO's facilities. The net result: increased release of pollutants and greenhouse gases, higher operating costs for HELCO's customers and financial stresses on IPPs.

1.7 Suppression of System Betterment to Absorb More Renewables

The high cost of importing fossil fuels and the abundance of renewable energy resources place Hawaii is a unique position to be the first developed economic zone powered entirely by renewable energy. The obstacles slowing down the realization of such future are rooted in an electricity infrastructure designed for a fossil-fired electricity industry and the inertia of the status quo. If public policy is seriously seeking high reliance on renewables then the impasse has to be broken. Curtailing IPP generators without compensation hides the costs of the inflexibility of the electricity generation and transmission infrastructures. Even if HECO moves beyond the talking stage with respect to upgrading the systems of its operating companies, the results <u>will not</u> be as effective as they should be as long as curtailment without compensation continues to be practiced.

2. Solution Principles

The solution we propose to deal with the curtailment issue and associated problems is based the following seven principles:

- A Do-No-Harm FiT;
- Ensure revenue neutrality;
- Establish the zero-curtailment price;
- Determine the revenue-neutral prices;
- Adopt FiT price-curtailment schedules;
- Pay prices at the expected curtailment levels; and
- Use balancing accounts for periodic settlements.

2.1 Do-No-Harm FiT

A successful feed-in tariff should facilitate the growth of renewable generation without harming prior investments. Attractive prices and a streamlined subscription process should encourage investors to seriously consider participating in the adopted FiT. Embracing a Do-No-Harm principle should seal their participation as investors realize that the risk of revenue erosion would be minimal. The commitment to safeguard prior investments should also ensure the continued contribution of operating renewable generators to Hawaii's need for clean energy.

2.2 Ensure Revenue Neutrality

The only way to ensuring that the adopted tariff would do no harm to any generator – regardless of the type of renewable development program it belongs to or the vintage of the facility – is to guarantee revenue neutrality irrespective of the level of curtailment the generator experiences.

2.3 Establish the Zero-Curtailment Price

A base price, symbolized by P_0, is the FiT rate of compensation for a facility that is presumed to be generating and delivering electricity to the grid without being curtailed by the purchasing utility (i.e., assuming zero curtailment). This rate is the very same prices that the PUC is contemplating to adopt for each category and size class to be considered eligible for FiT enrollment. The P_0 values to be adopted will be presumably based on the recommendations emerging from Docket No. 2008-0273 and the PUC's own inquiries. To assure correct information on how to set the base prices, it is important that the Commission makes it clear to all concerned that:

1. It intends to consider compensating generators for curtailed energy; and
2. The submitted estimates of P_0 values should assume zero curtailment risk.

Without such assertion, the quality of the submitted pricing information is highly suspect.

2.4 Determine the Revenue-Neutral Prices

This principle requires that the settlement price be proportional to the level of curtailment experienced. It follows then that compensation price is determined by:

$$P_c = \frac{P_0}{1 - FPCL} \tag{1}$$

Where

FPCL = Fraction of Power Curtailment Level

Equation 1 can be made part of every purchase power agreement (PPA) along with the adopted P_0 value.

2.5 Adopt FiT Price-Curtailment Schedules

For every PPA, there should be a schedule showing the series of compensation prices that would be paid for delivered energy at predetermined levels of curtailed deliveries. Each series P_c values would have to be calculated using Equation 1 and the applicable base price P_0. The underlying P_c values could be set at cumulative levels of curtailment increasing by intervals of 10%, 25% or some other values.

2.6 Pay Prices at Expected Curtailment Levels

Because data for final settlements may take time to be processed and validated, the purchasing utility should inform the seller ahead of time of the level of curtailment in the PPA schedule that it expects to enforce for system protection purposes. Settlement and compensation will be initially performed on the basis of the P_c value corresponding to the nominated curtailment level and the metered energy deliveries.

2.7 Use Balancing Accounts for Periodic Settlements

Because the actual level of curtailment is very likely to differ from the nominated amount, a reconciliation mechanism is necessary. This can be achieved by establishing a balancing account for each PPA contract to credit or debit the generator for under/over estimation of expected curtailment. This approach is very much the same as the method that utilities commonly use to update and settle various running revenue accounts.

3. Illustration

The following example should illustrate the application of the proposed solution:

A. Assume a base (zero-curtailment) price, P_0, of $0.2/kWh for a particular generator.

B. Apply the revenue-neutrality principle by using Equation 1 to establish the following – example – pricing schedule at 10% intervals of curtailment for said generator:

Curtailment Level	0.0%	20%	40%	60%	80%
Compensation Price, P_c ($/kWh)	0.20	0.25	0.33	0.50	1.0

C. Assume the utility expects a need to curtail deliveries from several generators by significant amounts. Further assume that the utility determines that it makes technical and economic sense to curtail as much as 40% of the production of the generator of interest to meet its reliability and system protection requirements.

D. The utility then informs the generator of its intention to curtail 40% of its otherwise deliverable generation and that the compensation price for all delivered energy would be $0.33/kWh (on the basis of above hypothetical schedule).

E. After metered data is validated and finalized, the utility established (with the help of the generator) that the amount actually curtailed is 50%. Applying Equation 1, the correct P_c value would then be $0.40/kWh, and the generator's balancing account would be credited with the difference accordingly.

4. Rationale

There are four reasons for adopting the proposed solution:

- It does away with the curtailment problems discussed earlier;
- *It reveals system inflexibility costs;*
- It meets the fairness criterion; and
- It ends a wrongful policy of penalizing variable (intermittent) resources.

4.1 Elimination of All Curtailment Problems

The root cause of the curtailment problems is the prospect of loss of earnings by generators who invested or may invest substantial moneys and efforts in expectation of selling all that can be produced by their facilities to the HECO utilities. Remove this threat and every one of the consequences discussed above goes away. The elimination of curtailment problems generates additional dividends. For example:

- The abolition of the risk of revenue erosion will lead to cheaper financing for future projects.
- Avoidance of project defaults (because price certainty will be coupled with guaranteed cost recovery) will translate into more effective FiT and other renewable development programs.
- FiT pricing will be more efficient than would have been the case because project developers would not need to guess how much curtailment and revenue erosion they would be facing (so that they could figure out the FiT contract price increases to lobby for). Likewise, the PUC would not need to forecast curtailment trends for the purpose of internalizing potential revenue losses into future FiT rates of compensation. FiT pricing would be based solely on information on parameters far less uncertain than curtailment levels, frequencies and timings (e.g., scheduled maintenance and well-known patterns of forced outages).
- There will be no discrimination between curtailable generators (interconnected primarily at the transmission and subtransmission levels) and non-curtailable generators (mostly on the distribution system) since both will be guaranteed revenue recovery. This means less risk of costly FiT court challenges that may lead to a public backlash and delay the transition to a fully renewables future.
- There will be no need to manage controversial curtailment queues as the primary reason for disputes (i.e., potential revenue losses) will no longer be relevant. Eliminating a queue restriction based on project seniorities is likely to improve system dispatch and operation significantly during low-load hours. This in turn leads to more efficient FiT and other renewables programs.

4.2 Shedding Light on the Cost of System Inflexibility

As stated before, the proper perspective for policy making purposes is to view Hawaii as a renewables economy zone. This means that the cause of the need to curtail renewable generation is the current inflexibility of the Islands' grids rather than the intermittent nature of the State's natural resources. Viewed from this perspective, the logical question that must be then asked is:

> ***What does the system's inflexibility cost ratepayers when curtailment of renewable energy deliveries is invoked?***

Setting aside the costs associated with environmental, health, and economic security issues, the answer to this query can be gleaned from the following formula:

$$\textit{System Inflexibility Costs} = \textit{Energy Avoided Costs} \times \left[1 - \frac{P_0}{P_c}\right] \qquad (2)$$

Equation 2, which has been derived by considering the cost of the replacement energy that has to be used to substitute for the renewable generation deliveries to be curtailed, bears a number of important messages:

Comparison of Capacity Credit Calculation Methods for Conventional Power Plants and Wind Power

Mikael Amelin, *Member, IEEE*

***Abstract*—Several methods for computing capacity credit values of power plants have been presented over the years. This paper uses an empirical approach to investigate and compare different properties of four typical capacity credit definitions. It is shown that the choice of definition indeed can have a significant impact on the results. Concerning three of the analyzed methods, it is found that important factors that influence the capacity credit are the overall generation adequacy and the penetration factor of the power plant; this means that the same generating unit will generally have a higher capacity credit if added to a system with high loss of load probability, and the unit will have a higher capacity credit if its installed capacity is small compared to the total installed capacity of the system. The results of the fourth method only depend on the size and availability of the generating units.**

***Index Terms*—Power generation peaking capacity, power system reliability, wind power generation.**

I. Introduction

THE capacity credit of a generating unit (or a block of generating units) represents the contribution of the unit to the generation adequacy of a power system. Capacity credits are of interest in several electricity markets around the world. For example, many liberalised electricity markets have experienced problems with peaking capacity units becoming unprofitable, as these units are used for a very limited time and the income of the small amounts of energy that the unit generates is not sufficient to cover the fixed costs. A solution to this problem can be to introduce separate capacity markets as in the northeastern U.S. [1]. Since "capacity" is not a natural commodity, the capacity market design has to define how much capacity a specific generating unit can sell, and capacity credit calculations could be useful to solve this task. Another issue where capacity credits are interesting is the integration costs of wind power. A wind farm which is generating 1 TWh/year does not contribute as much to the generation adequacy as a conventional power plant with equivalent annual energy output; hence, to maintain the same reliability of supply when conventional power plants are replaced by wind power there will be a need for back-up units such as open cycle gas turbines [2].

Capacity credit values have been studied for several decades. In particular, the capacity credit of wind power has received a lot of attention [3]–[8]. However, there is no single standard definition of what is meant by capacity credit, and there is a large variety of computation methods that have been applied. Hence, it is not surprising that there is large spread in the results obtained.

The objective of this paper is to put the different capacity credit definitions in a consistent framework, and to empirically investigate the properties of these definitions. The results should be useful to eliminate some of the confusion concerning capacity credits. The paper is organized as follows: Section II describes the capacity credit definitions that are used in this paper. The properties of these definitions are investigated using a set of test systems, which are defined and analyzed in Section III. The conclusions of the paper are presented in Section IV.

II. Definitions of Capacity Credit

The formal definition of capacity credit as well as the terminology used might vary widely in different sources. There are also several computation methods that can be used, ranging from sequential and nonsequential probabilistic methods including Monte Carlo simulation to diverse approximation methods. Classifying and comparing all these alternatives is beyond the scope of this paper, and the approach used here is therefore to identify a few central concepts and present them in a consistent framework based on classic probabilistic production cost simulation.

The motivation for choosing probabilistic production cost simulation is that it is a well-known method, it is computationally straightforward as well as reasonably accurate and fast. (The largest test system presented in Section III required about 10 s of computation time on a standard laptop computer, even though the system included more than 75 two-state random variables representing conventional units, one 281-state variable representing available wind power and one 35 000-state variable representing demand.) A disadvantage with this choice is that the method is based on the assumption that load and outages in the generating units are independent random variables, which might not be the case—in particular wind power and load can be positively or negatively correlated. However, correlations are not important in this study, and in a real simulation, the problem can be addressed by running separate simulations for seasons with different load and wind patterns (e.g., [7]).

Hence, the definitions of capacity credit values given below assume that there is a power system with a set of existing generating units indexed $1, \ldots, g-1$. The total installed capacity of these units is denoted $\hat{G}_{\text{tot}}$. The question is then how the generation adequacy of the system is affected if another unit (which is indexed g and has the installed capacity $\hat{G}_g$) is added.

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EXHIBIT "E"

The first three definitions are based on how the new unit affects the loss of load probability (*LOLP*). The *LOLP* is the probability that the load exceeds the available generation capacity, i.e.,

$$P(D > \hat{G}_{\text{tot}} - O_{\text{tot}}) = P(E > \hat{G}_{\text{tot}}) \tag{1}$$

where D is the physical load of the system, O_{tot} is the sum of all outages of the system and $E = D + O_{\text{tot}}$ is the equivalent load. The probability distribution of the equivalent load is represented by a duration curve, which is calculated according to the well-known Baleriaux–Booth formula [9], [10]:

$$\tilde{F}_{E_k}(x) = p_k \tilde{F}_{E_{k-1}}(x) + q_k \tilde{F}_{E_{k-1}}(x - \hat{G}_k) \tag{2}$$

where $\tilde{F}_{E_k}$ is the equivalent load duration curve including generating units $1, \ldots, k$, p_k is the availability of unit k, and $q_k = 1 - p_k$ is the unavailability of unit k. The resulting expression for the *LOLP* is then

$$LOLP_k = P\left(E_k > \sum_{g=1}^{k} \hat{G}_g\right) = \tilde{F}_{E_k}\left(\sum_{g=1}^{k} \hat{G}_g\right). \tag{3}$$

A. Equivalent Firm Capacity

The equivalent firm capacity of a generating unit is defined as the capacity of a fictitious 100% reliable unit which results in the same *LOLP* decrease as unit g [6], [7]. Let C_{EFC} denote the capacity of the fictitious unit. Since the availability is equal to unity for a 100% reliable unit, (2) yields that the load duration curve including the firm capacity (but excluding unit g) is equal to $\tilde{F}_{E_{g-1}}(x)$; hence, the firm capacity increases the installed capacity of the system from $\hat{G}_{\text{tot}}$ to $\hat{G}_{\text{tot}} + C_{\text{EFC}}$ without changing the shape of the equivalent load duration curve. The *LOLP* of the system with the firm capacity is then given by $\tilde{F}_{E_{g-1}}(\hat{G}_{\text{tot}} + C_{\text{EFC}})$. If this *LOLP* is to be equal to $LOLP_g$ (i.e., the *LOLP* including unit g), we get that the equivalent firm capacity is given by

$$C_{\text{EFC}} = \tilde{F}^{-1}_{E_{g-1}}(LOLP_g) - \hat{G}_{\text{tot}}. \tag{4}$$

A graphic interpretation of the equivalent firm capacity is given in Fig. 1.

B. Load Carrying Capability

The perhaps most well-known source of this method is a paper by Garver [11]. The idea of this capacity credit definition is that each new unit that is added to a system allows the load to increase without compromising the generation adequacy. When unit g is added to the system, the risk of power deficit decreases from $LOLP_{g-1}$ to $LOLP_g$. The load carrying capability of unit g is here defined as the largest constant load, C_{ELCC}, which can be added to the system without the risk of power deficit exceeding the earlier level $LOLP_{g-1}$.[1]

The equivalent load duration curve including unit g and the constant load is given by

[1]Garver and many others define load carrying capability by studying how much the *peak* load can increase when a unit is added. However, the peak load of a system is not always easily defined; therefore, a definition based on a constant load is more straightforward for the purpose of this paper.

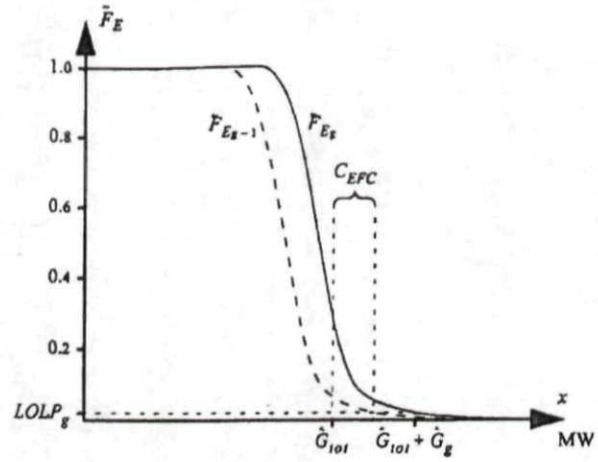

Fig. 1. Illustration of equivalent firm capacity.

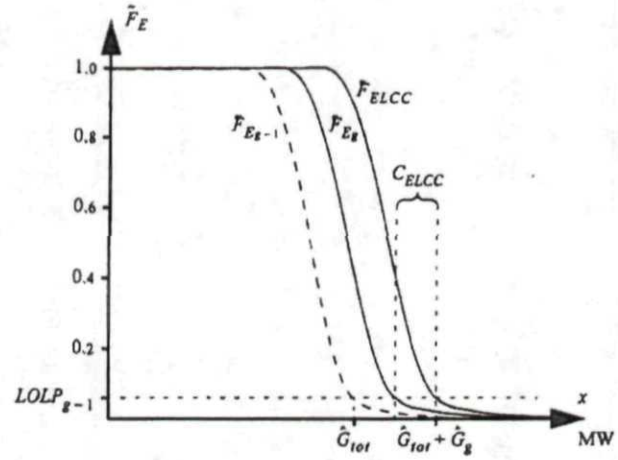

Fig. 2. Illustration of equivalent load carrying capability.

$$\begin{aligned} \tilde{F}_{\text{ELCC}}(x) &= P(E_g + C_{\text{ELCC}} > x) \\ &= P(E_g > x - C_{\text{ELCC}}) = \tilde{F}_{E_g}(x - C_{\text{ELCC}}) \end{aligned} \tag{5}$$

i.e., $\tilde{F}_{\text{ELCC}}$ will have the same shape as $\tilde{F}_{E_g}$, but will be shifted to the right by C_{ELCC}. The installed capacity of the system is still $\hat{G}_{\text{tot}} + \hat{G}_g$, which means that if the *LOLP* should not change when unit g and the constant load are added to the system, then we must have $\tilde{F}_{E_g}(\hat{G}_{\text{tot}} + \hat{G}_g - C_{\text{ELCC}}) = LOLP_{g-1}$. Hence, we get that the equivalent load carrying capability is given by

$$C_{\text{ELCC}} = \hat{G}_{\text{tot}} + \hat{G}_g - \tilde{F}^{-1}_{E_g}(LOLP_{g-1}). \tag{6}$$

A graphic interpretation of the load carrying capability is given in Fig. 2.

C. Equivalent Conventional Power Plant

This measure of the capacity credit is defined in a similar manner as the firm capacity, but in this case unit g is not compared to a 100% reliable unit, but to a reference "conventional" generating unit. Assume that the reference unit has the availability p_{ECC}. The question is when which capacity, C_{ECC}, the equivalent conventional power plant must have, in order to result in the same *LOLP* as would be obtained by adding unit g to the existing units. The equivalent load duration curve including the equivalent conventional power plant, but excluding unit g, will be equal to

$$\tilde{F}_{\text{ECC}}(x) = p_{\text{ECC}}\tilde{F}_{E_{g-1}}(x) + (1 - p_{\text{ECC}})\tilde{F}_{E_{g-1}}(x - C_{\text{ECC}}). \quad (7)$$

Since $\tilde{F}_{\text{ECC}}(x)$ should be equal to $LOLP_g$ for $x = \hat{G}_{\text{tot}} + C_{\text{ECC}}$, we get that

$$C_{\text{ECC}} = \tilde{F}_{E_{g-1}}^{-1}\left(\frac{LOLP_g - (1 - p_{\text{ECC}})\tilde{F}_{E_{g-1}}(\hat{G}_{\text{tot}})}{p_{\text{ECC}}}\right) - \hat{G}_{\text{tot}}. \quad (8)$$

The reference availability p_{ECC} can be chosen arbitrarily in the range from $1 - LOLP_g/LOLP_{g-1}$ to 1, where the lower limit is due to the fact that the inverse of the equivalent load duration curve, $\tilde{F}_{E_{g-1}}^{-1}(y)$ does not exist for $y < 0$.

D. Guaranteed Capacity

The concept of guaranteed capacity was introduced in the dena study [8]. The method does not consider the load of the system, but only the available generation capacity with and without unit g. The available generation capacity can be calculated using a similar convolution formula as (2) as follows:

$$\tilde{F}_{G_k}(x) = p_k\tilde{F}_{G_k-1}(x - \hat{G}_k) + q_k\tilde{F}_{G_{k-1}}(x) \quad (9)$$

where $\tilde{F}_{G_k}$ is the available capacity duration curve. The guaranteed capacity of a system is defined as the least capacity which can be expected to be available with a given probability, ρ, which in [8] is referred to as the "level of supply reliability." However, the ρ value should not be mistaken for the *LOLP* of the system; the latter is a measure of the reliability of supply (expressed as the probability that the load exceeds the available resources), whereas the former is an arbitrarily chosen parameter, which is not directly related to the system performance. To avoid confusion, ρ will be referred to as the "guarantee probability parameter" in this paper.

The capacity credit of unit g is now defined as the difference in guaranteed capacity with and without unit g, i.e.,

$$C_{\text{GC}} = \tilde{F}_{G_g}^{-1}(\rho) - \tilde{F}_{G_{g-1}}^{-1}(\rho). \quad (10)$$

A graphic interpretation of the guaranteed capacity is given in Fig. 3.

Even though this definition does not use the equivalent load duration curve—unlike the other three described above—it can be noted that the computational burden will not decrease considerably. In this method, g random variables representing the available capacity have to be added using a convolution formula, whereas when the equivalent load duration curve is computed,

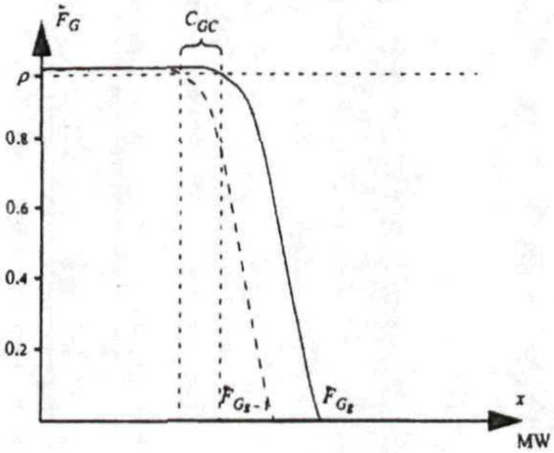

Fig. 3. Illustration of guaranteed capacity.

it is necessary to add $g + 1$ random variables (one random variable representing the load and g random variables representing outages in generating units).

III. Empirical Study

There are a lot of factors who possibly could influence the capacity credit of a generating unit. Attempts have been made to identify such factors in analytical studies (see, for example, [6]), but such studies requires a lot of simplifying assumptions. Therefore, this paper will use an empirical approach to compare the results of applying the four capacity credit definitions from Section II to a set of different system configurations. The influence of the system properties on the capacity credit will be investigated for a conventional unit as well as a block of wind power plants.

A. Test System Configurations

All test systems consists of a normally distributed load and a set of existing generating units, which all have the same availability. It is assumed that the load and outages in the generating units are independent.

The values of the mean and standard deviation of the load, and the number of units and their availability is based on five basic setups of the existing generating units, as described in Table I. Each basic setup is then varied by combining the following values.

- **Mean load**. The mean load can either be 9/15, 10/15, or 11/15 of the installed capacity.
- **Load variance.** The standard deviation of the load can either be 8%, 10%, or 12% of the mean load.
- **Availability of the existing units**. The availability of each of the existing units is either set to 90%, 92%, or 94%.

All together, this results in 135 different test system configurations. For each configuration, the capacity credit of an additional 1000 MW conventional two-state unit with 90% availability is calculated using each of the definitions described in Section II. Moreover, the same calculations are also performed for a block of wind power plants with a total installed capacity of 2800 MW. The probability distribution of the total available generation capacity from this block of wind power plants is shown in Fig. 4. It can be noted that the probability distribution

TABLE I
EXISTING UNITS FOR THE FIVE BASIC TEST SYSTEM SETUPS

Setup	Number of and size of existing units	Total capacity of the existing units [MW]
1	4 × 1 000 MW, 2 × 800 MW, 5 × 500 MW, 6 × 250 MW, 6 × 240 MW, 6 × 230 MW, 6 × 220 MW, 6 × 210 MW	15 000
2	4 × 1 000 MW, 4 × 800 MW, 7 × 500 MW, 7 × 250 MW, 7 × 240 MW, 7 × 230 MW, 7 × 220 MW, 7 × 210 MW	18 750
3	5 × 1 000 MW, 6 × 800 MW, 7 × 500 MW, 8 × 250 MW, 8 × 240 MW, 8 × 230 MW, 8 × 220 MW, 8 × 210 MW	22 500
4	7 × 1 000 MW, 6 × 800 MW, 10 × 500 MW, 9 × 250 MW, 8 × 240 MW, 8 × 230 MW, 8 × 220 MW, 8 × 210 MW	26 250
5	7 × 1 000 MW, 5 × 800 MW, 15 × 500 MW, 10 × 250 MW, 10 × 240 MW, 10 × 230 MW, 10 × 220 MW, 10 × 210 MW	30 000

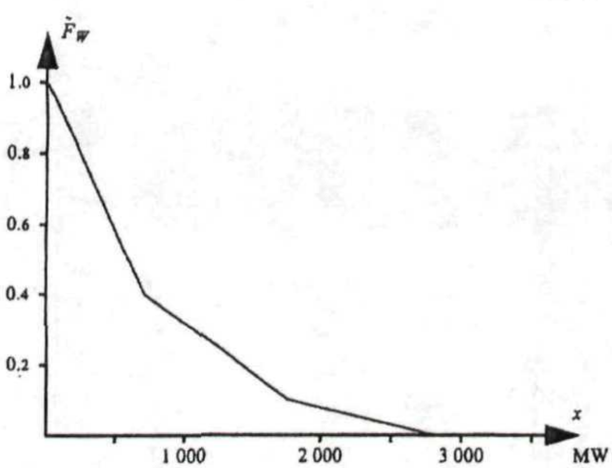

Fig. 4. Available wind power generation capacity for a block of wind power plants. The probability distribution accounts both for the wind speeds of the different sites of the wind power plants and the forced outage rate of individual units.

is based on Swedish data from [12] and that the size of wind power block has been chosen so that the annual energy output is roughly the same as for the 1000-MW conventional unit.

B. Comparison Between the Definitions

A compilation of the results are presented in Figs. 5 and 6. The most immediate conclusion is that the choice of capacity credit definition can have a significant impact on the result. For the conventional unit, the highest capacity credit can be up to 20% higher than the lowest capacity credit for the same system. For the wind power block, the corresponding differences can be up to 30%! However, it can be noted that variations of the three *LOLP*-based methods (i.e., equivalent firm capacity, equivalent load carrying capability and equivalent conventional capacity) are rather consistent. There is no larger difference between equivalent firm capacity and equivalent load carrying capability; the latter gives only slightly higher results.

C. Relation Between Capacity Credit and LOLP

Another interesting observation is that all capacity credit values except the guaranteed capacity show a clear correlation to the *LOLP*. The results in Figs. 5 and 6 have been ordered according to increasing *LOLP* before the additional unit was added (i.e., the *LOLP* including only the existing units). It is not necessarily true that a system with high *LOLP* results in higher capacity credits than a system with low *LOLP*, but there is definitely a trend towards higher capacity credit values for systems with high *LOLP*. The trend is even more clear in Figs. 7 and 8, which show equivalent firm capacity as a function of the *LOLP*. The same type of figures for equivalent load carrying capability and equivalent conventional capacity would have a similar look. The guaranteed capacity on the other hand, does not show any relation to the *LOLP* at all, as can be seen in Figs. 9 and 10.

D. Relation Between Capacity Credit and Penetration Factor

The penetration factor, which has been identified as important for the capacity credit of wind power [3]–[6], is in this paper defined as the capacity of the additional unit compared to the total capacity of the existing units and the additional unit, i.e.,

$$\frac{\hat{G}_g}{\hat{G}_{\mathrm{tot}} + \hat{G}_g}. \tag{11}$$

In this case, the penetration level will depend on the installed capacity of the test system, i.e., there will be one penetration level for each of the basic setups listed in Table I. To compare the impact of penetration level to the impact of the *LOLP*, all results of the equivalent firm capacity have been plotted in Figs. 7 and 8. The figures shows that the capacity credit of both conventional power and wind power is in fact related to the penetration level—it can be seen that for each *LOLP* level, the capacity credit of the low penetration level systems tend to be higher than for high penetration level systems. However, the figure also shows that the impact of the *LOLP* seems to be equally important; the low penetration level capacity credit when the *LOLP* is around 0.001% is smaller than the high penetration level capacity credit when *LOLP* is above 5%.

The relation between penetration factor and capacity credit expressed as equivalent load carrying capability or equivalent conventional capacity is similar to the relation for the equivalent firm capacity. However, Figs. 9 and 10 show that there is hardly any predictable relation between the guaranteed capacity and the penetration factor.

E. Relation Between Capacity Credit and Mean Capacity

It can also be interesting to compare the capacity credit to the expectation value of the available generation capacity. As seen in Table II, the capacity credit is generally smaller than the mean available generation. The equivalent conventional capacity can however in some system be larger than the mean, which is due to the fact that a conventional unit with 90% availability is compared to a reference unit with 95% probability. Another observation is that the ratio for wind power is lower than for the conventional unit.

F. Further Comments on Equivalent Conventional Capacity

The capacity credit expressed as equivalent conventional capacity is depending on the availability of the reference conventional unit, p_{ECC}, as defined in Section II-C. This parameter will of course influence the obtained capacity credit value—it

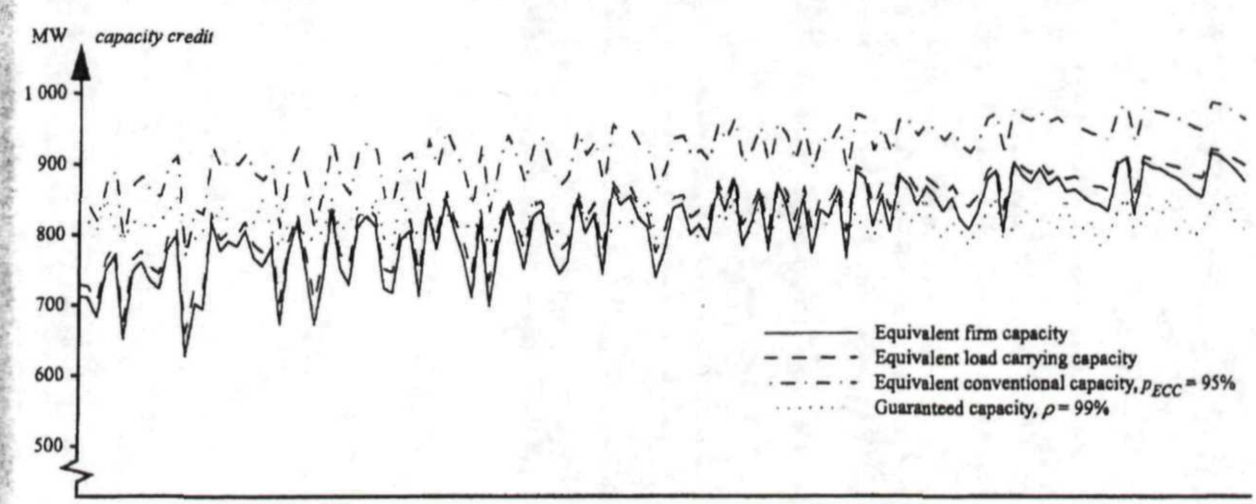

Fig. 5. Capacity credit of a 1000-MW conventional power plant for 135 test systems.

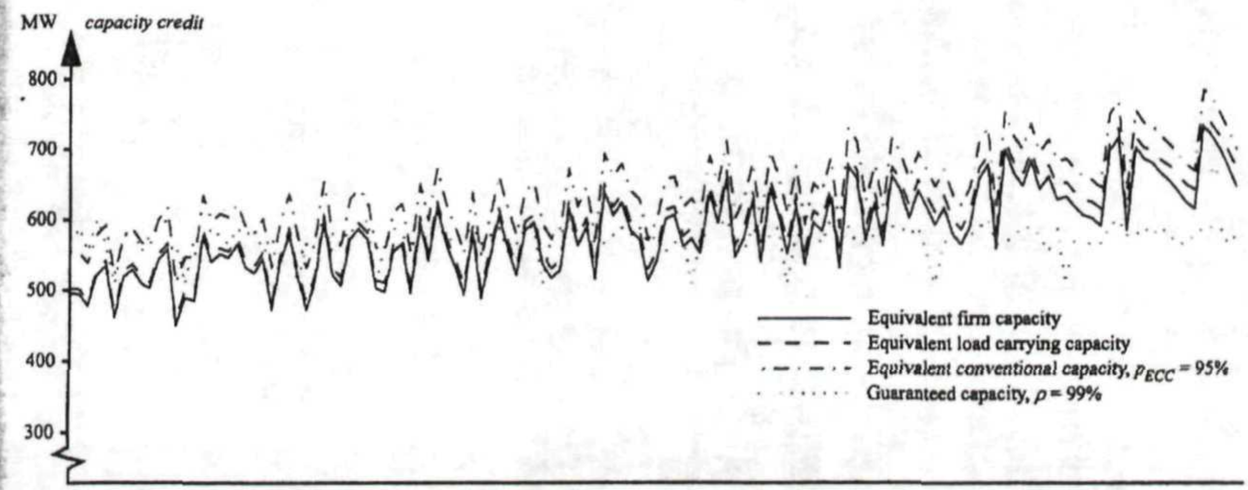

Fig. 6. Capacity credit of a block of 2800-MW wind power for 135 test systems.

is easier to match a reference unit with poor availability. Hence, lower p_{ECC} values should provide higher capacity credits. The capacity credit as a function of p_{ECC} is shown in Fig. 11 for one of the test systems (a similar behavior can be observed in all other systems as well). The figure shows that the equivalent conventional capacity increases for both the conventional unit and the wind power block when p_{ECC} is decreased, but the capacity credit of the conventional unit is increasing relatively faster. Although the differences are quite small, a high p_{ECC} value could be chosen for a study which is intended to show small differences between conventional units and wind power, whereas a low p_{ECC} could be used to emphasize the difference. Such arbitrariness is of course not good for the credibility of the results, and considering the similarity between this method and equivalent firm capacity or equivalent load carrying capability, it seems more preferable to use one of those two methods.

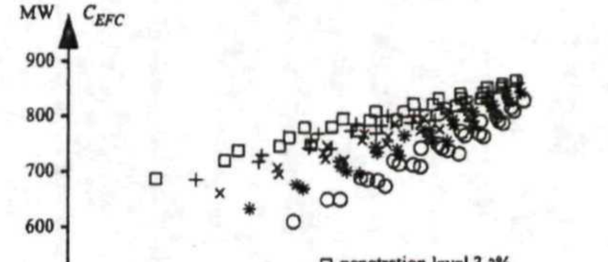

Fig. 7. Equivalent firm capacity of the 1000-MW conventional unit.

G. Further Comments on Guaranteed Capacity

The capacity credit expressed as guaranteed capacity is depending on the guarantee probability parameter, ρ, as defined in Section II-D. The capacity credit as a function of ρ is shown in Fig. 12 for one of the test systems (a similar behavior can be observed in all other systems as well).

The figure shows that lowering the guarantee probability parameter does not necessarily increase the guaranteed capacity.

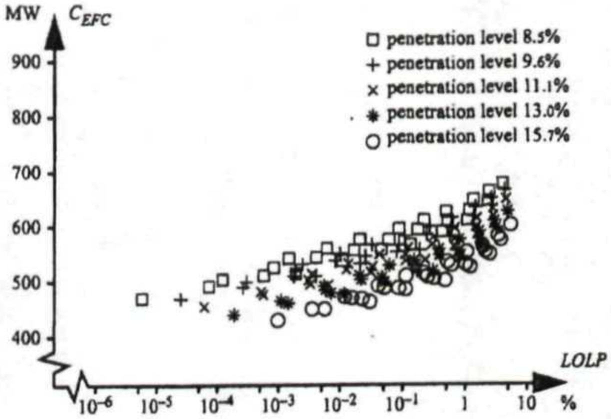

Fig. 8. Equivalent firm capacity of the 2800-MW wind power block.

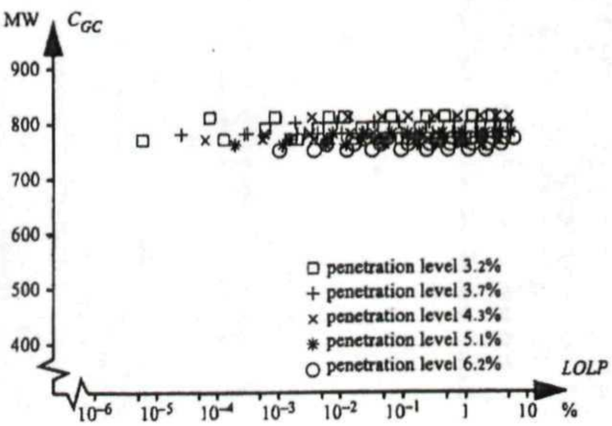

Fig. 9. Guaranteed capacity of the 1000-MW conventional unit.

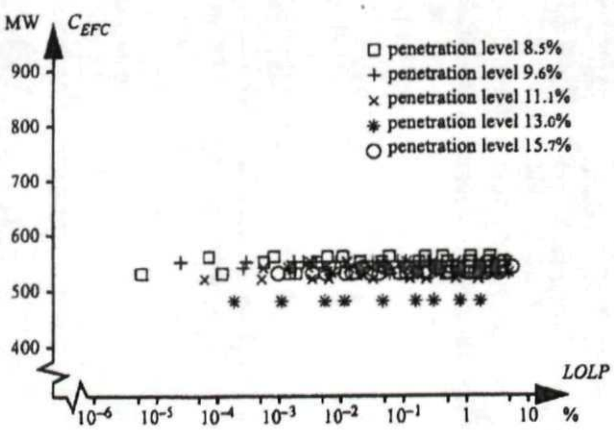

Fig. 10. Guaranteed capacity of the 2800-MW wind power block.

TABLE II
CAPACITY CREDIT IN % OF MEAN AVAILABLE GENERATION

Unit	Equivalent firm capacity	Equivalent load carrying capacity	Equivalent conventional capacity, p_{ECC} = 95%	Guaranteed capacity, ρ = 99%
Conventional	68–96	71–97	82–103	83–90
Wind block	53–84	54–85	60–89	59–69

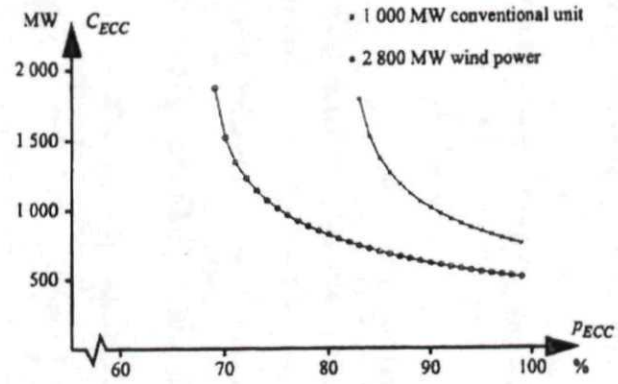

Fig. 11. Impact of the reference availability parameter, p_{ref}, on the capacity credit expressed as equivalent conventional capacity.

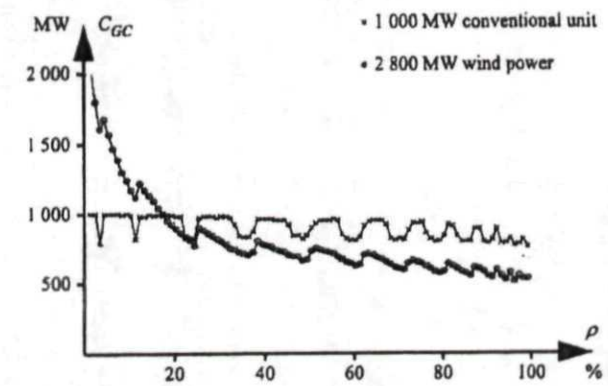

Fig. 12. Impact of the guarantee probability parameter, ρ, on the capacity credit expressed as guaranteed capacity.

This might seem as a contradiction; if at least C_1 MW are available with a probability of ρ_1, and at least C_2 MW are available with a probability of ρ_2 when one would expect that $C_1 > C_2$ if $\rho_1 < \rho_2$. This interpretation is however only correct if we study one specific probability distribution of the available generation capacity, but the guaranteed capacity of the last added unit is according to (10) defined as *the difference between values from two different probability distributions*. The consequences are best understood by studying a small system, as in Fig. 13. The available capacity of a conventional unit is a two-state discrete random variable; hence, the total generation capacity duration curve will get a typical staircase shape. However, the two duration curve that are to be compared do not "take a step" simultaneously, which means that for some values of ρ, the difference will be equal to the installed capacity of the additional unit, and sometimes the duration curves coincide. There will be a smoothing effect on the duration curves if a system has a large number of units with varying installed capacity, and the curves will hardly coincide, but yet a "step" in a large unit can significantly increase or decrease the difference between $\tilde{F}_{G_g}^{-1}(\rho)$ and $\tilde{F}_{G_{-1}}^{-1}(\rho)$ in a similar manner as observed in Fig. 13. The impact of this "step effect" is depending on the choice of ρ as well as the system configuration, and is therefore very hard to predict.

Neglecting the variations due to the step effect, Fig. 13 shows that the guaranteed capacity increases for both the conventional unit and the wind power block when ρ is decreased, but the impact is much larger on wind power, especially for low values of ρ. As for equivalent conventional capacity, this could open for

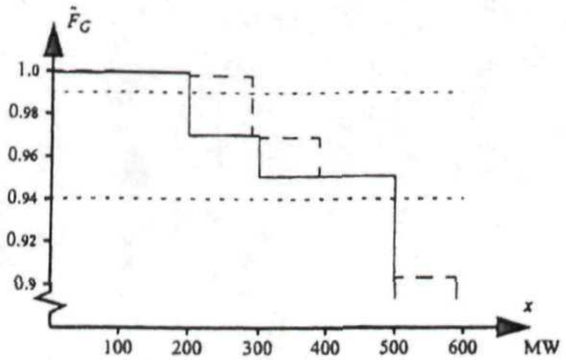

Fig. 13. Guaranteed capacity calculation for an example from [8]. The solid line shows the available generation capacity duration curve for a system with two existing units: 300 MW, 97% availability and 200 MW, 98% availability, respectively. The dashed line shows the duration curve after adding a 90-MW unit with 95% reliability.

the possibility to set the parameter value such that a particular result is favoured.

The advantages of using the guaranteed capacity definition is that the computational burden is slightly smaller and that no load data is required (both of these advantages are due to the fact that the guaranteed capacity does not consider the equivalent load duration curve). It is open for discussion if these advantages are sufficient to compensate for the arbitrariness and the fact that the guaranteed capacity does not reflect the actual contribution of a generating unit to the generation adequacy of the system.

IV. Conclusion

This paper has described four general definitions of capacity credit, which have then been compared to each other in an empirical study. The results show that the choice of definition can have a significant impact on the obtained capacity credit. Two definitions, equivalent firm capacity and equivalent load carrying capacity, provide consistent results. The third method, equivalent conventional capacity, is differing from the first two methods in that the results depend on an arbitrarily chosen parameter, but besides that, it follows the same trends as equivalent firm capacity and equivalent load carrying capacity. The results of the last method, guaranteed capacity, are depending on an arbitrary parameter in a quite unpredictable manner. Moreover, the capacity credit values obtained by this method are not correlated to the results of the other three methods.

The main difference between the four definitions is that all capacity credits but the guaranteed capacity are based on how the last added unit influences the overall generation adequacy (expressed by the *LOLP* of the system), whereas the guaranteed capacity method measures only the impact of the last unit on the total available generation capacity. This means that the guaranteed capacity does not directly take into account if the available capacity is needed or not, since the load is not included in the modelling.

The three definitions based on *LOLP* show a clear correlation between the *LOLP* of the system and the capacity credit; a unit will tend to have a higher capacity credit (i.e., contribute more to the generation adequacy) if added to a system with high *LOLP*. There is also a correlation between the penetration factor and the capacity credit, but the results here indicate that influence of the penetration factor is not as strong as the influence of the *LOLP*.

Conventional units as well as wind power have been examined in the paper, and similar results were obtained in both cases. The conclusion is that the equivalent firm capacity and equivalent load carrying capability will be lower than the expectation value of the available generation capacity, but the capacity credit will always be larger than zero. (Similar results will can be obtained for the other two methods, as long as extreme values are avoided for the arbitrary parameters.) The study also confirms the statement that when comparing units with approximately the same annual energy output, the capacity credit will generally be lower for wind power than for conventional units.

The empirical study in this paper has demonstrated that studies involving capacity credits must take into account that the choice of capacity credit definition might influence the results. In particular, the capacity credit expressed as equivalent conventional capacity or guaranteed capacity depends on arbitrary parameter values. In addition, the guaranteed capacity does not directly measure the capability of a power plant to reduce the loss of load probability of a system. Therefore, it is recommended to use one of the other two definitions, i.e., equivalent firm capacity or equivalent load carrying capacity.

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Review of "Hawaiian Electric Light Company Wind Generation Impact Study - Phase II," dated December 29, 2006; Prepared by Electric Power Systems, Inc.

The appendices were not provided making the study difficult to comprehend and critique.

The study does not include the re-powered Keahole generating plant. The new Keahole power plant will be efficient and likely to be operating most of the time. If designed properly, it will greatly enhance Island operation; it should be quite responsive and flexible. Without this plant in the model, the study is of little value.

The study models a repetitive power flow pattern at the Apollo plant while wind power variations are highly variable and nearly random. Modeling AGC characteristics as part of the wind plant power variation makes no sense. Assuming that HELCO's AGC system only responds to a rise in frequency is not rational. Additionally, the Apollo power variations modeled are six times those that are allowed to occur or that do occur.

The oscillations in frequency following load shedding suggest a significant modeling problem with the generator governors, not a system problem that must be addressed by increasing the amount of thermal generation on-line.

The study models increasing amounts of HELCO thermal generation at higher system load levels and uses the improved system response to conclude that more thermal generation needs to be run under light load conditions. While that conclusion is intuitively correct, no casework is presented to confirm that conclusion or separate the effect of thermal units from other system changes that occur when load levels change.

The inertia of customer's motors has apparently been neglected.

Oscillatory stability problems are said to be evident but well known economical solutions are not presented. Without the appendices, we have only the author's interpretation of his casework to work from. However, that interpretation seems vague and suspect.

The study states "The interaction between wind generation, AGC and thermal generation governors is virtually impossible too (sic) predict using transient stability simulations." This is untrue. Such simulations are the only appropriate analysis method and are quite effective if done properly. Recordings of wind plant power are used to "drive" the system model. The Hawi wind plant was available and could have been used for this purpose in the EPS study.

If the assertion discussed next above is true, the study results should not be nearly as definitive as they are. Indeed, the results in Table 10 are senseless. No practical electric power system will exhibit oscillations at the frequencies listed in this table.

The last paragraph on page 27 includes the words "The trend toward more oscillatory frequency control in simulations will most likely be magnified in the actual system control when AGC and normal load changes interact with the variation in wind generation." Quite the opposite occurs in reality. The beneficial effect results from diversity among variations in load and variable generation sources.

The study provides virtually no useful insight into the behavior or limitations of the HELCO system to accommodate renewable generation.

Harrison Clark
May 19, 2009

EXHIBIT "F"

CERTIFICATE OF SERVICE

The foregoing Opening Statement Of Position was served on the date of filing by hand delivery or electronically transmitted to each such Party.

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